

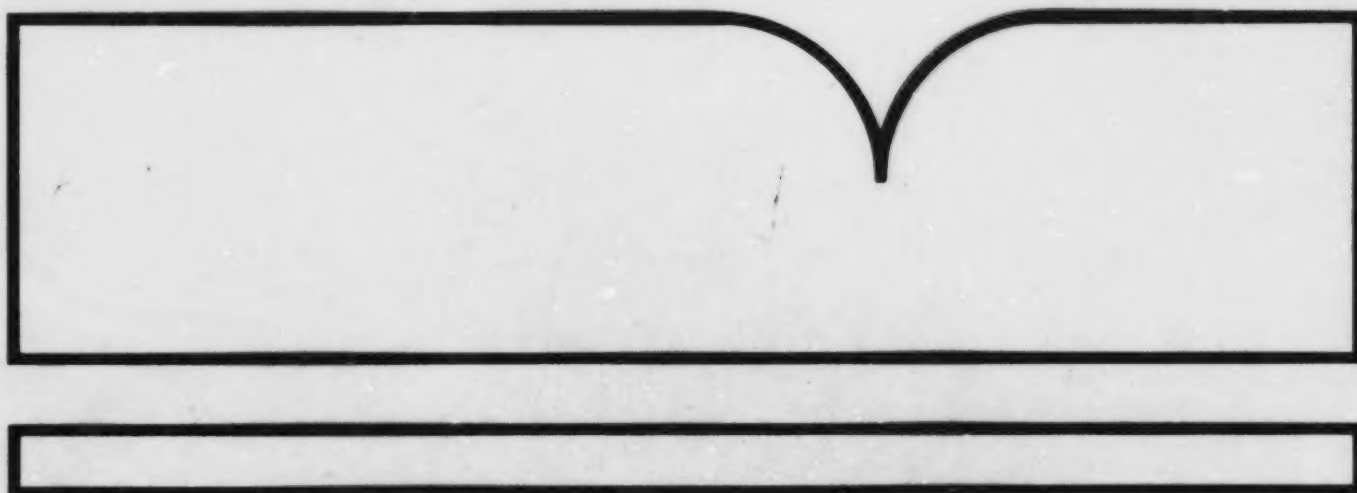
Use of Coal Cleaning for Compliance with
SO₂ Emission Regulations

Battelle Columbus Labs., OH

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USE OF COAL CLEANING FOR COMPLIANCE
WITH SO₂ EMISSION REGULATIONS

by

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FOREWORD

Many elements and chemical compounds are known to be toxic to man and other biological species, but our knowledge concerning the levels and conditions under which these substances are toxic is extremely limited. Little is known concerning the emission of these pollutants from industrial processes and the mechanisms by which they are transported, transformed, dispersed, or accumulated in our environment.

Portions of the Federal Clean Air Act, the Resource Conservation Recovery Act, and the Federal Water Pollution Control Act require the U.S. Environmental Protection Agency (EPA) to identify and regulate hazardous or toxic substances which result from man's industrial activities. Industrial pollutants are often identified only after harmful health or ecological effects are noted. Remedial actions are costly, the damage to human and other biological populations is often irreversible, and the persistence of some environmental contaminants may endanger future populations.

EPA's Office of Research and Development (ORD) is responsible for health and ecological research, studies concerning the transportation and fate of pollutants, and the development of technologies for controlling industrial pollutants. The Industrial Environmental Research Laboratory, an ORD organization, is responsible for development of pollution control technology and conducts a large environmental assessment program. The primary objectives of this program are:

- The development of information on the quantities of toxic pollutants emitted from various industrial processes--information needed to prioritize health and ecological research efforts.
- The identification of industrial pollutant emissions which pose a clearly evident health or ecological risk and which should be regulated.
- The evaluation and development of technologies for controlling pollution from these toxic substances.

The coal cleaning environmental assessment program has as its specific objectives the evaluation of pollution and pollution control problems which are unique to coal preparation, storage, and transportation. The coal preparation industry is a mature yet changing industry and in recent years significant achievements have been made in pollution abatement.

In focusing on the effectiveness and efficiency of coal cleaning processes as methods of reducing the total environmental impact in the use of energy derived from coal, this report deals with the results of an analysis of the potential for use of coal cleaning as an SO₂ emission control technique. Implementation of defined needed actions for overcoming identified barriers should greatly increase the use of coal cleaning with concomitant environmental and economic benefits to the nation.

ABSTRACT

The results of an overall evaluation of the potential role for coal cleaning as a means of controlling SO₂ emissions from coal-fired stationary sources are presented in this report. The objectives were to examine the capabilities of coal cleaning in the light of various existing and proposed SO₂ emissions regulations to determine the applications in which the technology would be most useful, to identify the barriers which exist to prevent wider application of coal cleaning, and to describe actions which should be taken to overcome these barriers.

A large amount of information about coal is compiled as resource data, including data on the coal reserve base, present and projected coal production, coal cleanability, current and projected coal use by utilities and industry, size and age distribution of coal-fired facilities, and the nature of coal contracts.

The environmental impacts of coal cleaning are compared with other sulfur removal strategies such as flue gas desulfurization (FGD) and the use of low-sulfur coal, and, similarly, cost comparisons are made among the various alternatives for SO₂ control. The results of the cost analyses show that, when all costs and benefits to utilities of using physical coal cleaning (PCC) are properly evaluated, an economic superiority for physical coal cleaning generally exists, even if supplemental application of another method, FGD, must be used to achieve full compliance with applicable New Source Performance Standards (NSPS) or State Implementation Plan (SIP) emission limits. Comparisons also are made between the quantities of coal which could be made available through the use of various coal cleaning processes to meet different emission standards and the quantities of coal currently required by utility and industrial facilities operating under each of the standards. The results show clearly the usefulness of coal cleaning in producing coal to satisfy SIP's or the 1971 NSPS.

Barriers to the implementation of coal cleaning are identified in each of several areas: technical, institutional, environmental, economic and social, legislative and regulatory, and transportation. The common theme encountered is that of uncertainty. Investments in coal cleaning facilities may be deferred because of uncertainties. Among these are:

- Questions related to technical details, e.g., lack of performance data from a commercial plant showing that clean coal can be produced with the reduced sulfur content predicted by experimental washability data
- Changing environmental regulations
- Ultimate profitability of the investment.

Actions needed to overcome these barriers are recommended. These include nine technical research and development programs, and various actions to implement one of two policies: either a policy to provide growth in coal cleaning by assuring that coal cleaning is competitive in the marketplace and that coal users believe that it is worth the investment, or as an alternative, a policy to require that all high sulfur coal be cleaned before it is burned.

This report was submitted in partial fulfillment of Contract No. 68-02-2163 by Battelle's Columbus Laboratories under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period July 1, 1977, to June 1, 1979, and work was completed June 1, 1981.

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ABBREVIATIONS

AIME	American Institute of Mining, Metallurgical, and Petroleum Engineers
ARCO	Atlantic Richfield
AQCRs	Air Quality Control Regions
AT	air tables
BACT	best available control technology
BCR	Bituminous Coal Research
BOM	Bureau of Mines
Btu	British thermal unit
CCC	chemical coal cleaning
cfm	cubic feet per minute
COD	chemical oxygen demand
CPSM4	Coal Preparation Simulation Model--Version 4
CRF	capital recovery factor
CS	crushing and sizing
dba	A-weighted decibels
DER	Pennsylvania Department of Environmental Research
DMC	dense medium cyclones
DMV	dense medium vessels
dscf	dry standard cubic foot
EDS	Energy Data Systems (EPA file)
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act (P.L. 94-163, enacted December 27, 1975)
EPRI	Electric Power Research Institute
ERDA process	Energy Research and Development Administration process
F	froth flotation units
FEA	Federal Energy Administration
FGD	flue gas desulfurization
FOB	free on board
fpn	feet per minute
fps	feet per second
GAO	Government Accounting Office
gpm	grams per minute
gr/dscf	grains per dry standard cubic foot

ABBREVIATIONS
(Continued)

H	Scenario H in Appendix A
HC	hydrocyclones
ICF	ICF, Incorporated
IERL/RTP	EPA's Industrial Environmental Research Laboratory, Research Triangle Park
IGT process	Institute for Gas Technology process
IRS	Internal Revenue Service
J	jigs
JPL process	Jet Propulsion Laboratory process
kg	kilo-kilograms
KVB	KVB Corporation
kW	kilowatt
kWh	kilowatt-hour
L	Scenario L in Appendix A
LOL	Ledgemont process
M	Scenario M in Appendix A
M	mesh
MCCS	multistream coal cleaning system
MFBI	Major Fuel Burning Installations
MISTT	Midwest Interstate Sulfur Transformation and Transport Programs of EPA
MW	megawatt
MWe	electrical megawatts
NAAQS	national ambient air quality standards
NCA	National Coal Association
NEPA	National Environmental Policy Act
NSPS	New Source Performance Standards
NSSPS	New Stationary Sources Performance Standards
O&M costs	operating and maintenance costs
ORD	Office of Research and Development, EPA
O.S.	organic sulfur
P	number of primary FGD modules
PCC	physical coal cleaning
PCRBs	pollution control revenue bonds
PEDCo	PEDCo Environmental, Inc.
ppm	parts per million
P.S.	pyritic sulfur
PSD	prevention of significant deterioration
psi	pounds per square inch
PUC	Public Utility Commission

ABBREVIATIONS
(Continued)

ROM	run of mine
RPAM	Reserve Processing Assessment Model
RSD	relative standard deviation
s	number of spare FGD modules
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SURE	EPRI's Sulfate Regional Experiment
SURE I	Sulfate Regional Experiment I
TD	thermal dryers
tph	tons per hour
TRW	TRW Corporation
TSP	total suspended particulates
TVA	Tennessee Valley Authority
UMW	United Mine Workers
USGS	U.S. Geological Survey
USM	Teknekron's Utility Simulation Model
WT	wet concentrating cyclones

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- (1) "An Evaluation of Institutional, Economic and Social, Regulatory and Legislative Barriers to Investment in Physical Coal Cleaning as a Sulfur Dioxide Emissions Control Strategy", December 15, 1977.
- (2) "An Evaluation of Physical Coal Cleaning as a Sulfur Dioxide Emissions Control Strategy in the Electric Utility Sector", April, 1978.
- (3) "A Summary of Studies of Atmospheric SO₂-Sulfate Transformation and Long-Range Transport: Initial Results and Implications for Controls", July 31, 1978.

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SECTION 1

INTRODUCTION

What is the best way to control the emission of sulfur dioxide (SO_2) resulting from coal combustion? The answer to this complex question depends upon a number of factors, including the characteristics of the coal being burned, the size and type of the combustion facility, whether the facility is existing or being planned, the location of the facility, and the emission regulations the facility is required to meet.

Physical coal cleaning has been used for many years as a means of removing ash from coal before combustion or coke manufacture. Conventional coal cleaning processes also remove part of the sulfur from the coal, and modified coal cleaning processes for enhancing sulfur removal are being implemented. Thus, coal cleaning is one method for reducing SO_2 emissions. The usefulness of coal cleaning in this role depends upon the same factors already listed, and this study was undertaken to evaluate the potential for coal cleaning, in the light of these factors, and to determine the applications in which the technology would be most useful. A further objective of this study has been to identify barriers which hinder the adoption of coal cleaning for SO_2 control and to recommend actions to overcome these barriers.

This report includes the results of analyses of a broad range of topics required in order to meet the objectives. For many of these topics, summaries of the findings are given in the body of the report with details of the methodology and the results given in various appendices.

The U.S. Environmental Protection Agency recently published New Stationary Sources Performance Standards (NSSPS) for electric utility steam generating units (Federal Register, June 11, 1979). Because this report was essentially completed at the time the standards were published, "proposed revisions to the New Source Performance Standards (NSPS)" are mentioned in some sections.

These references should now be interpreted to mean the recently published NSSPS. In addition, of course, many calculations throughout the report are based on the old NSPS which were published in 1971. Because the points made by such calculations remain valid, it was not necessary to recalculate the tables and other examples using the newer standards.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

The major findings of this study are derived from an assessment of the cleanability of U.S. coals, from an analysis of the increase in the quantities of compliance coals achievable through coal cleaning, from a comparative evaluation of the costs of various SO₂ control methods, and from an analysis of barriers to the expanded use of coal cleaning. Additional background information has been developed and compiled, including: considerations of the variability of sulfur in coal; data on coal production, coal use, coal reserves, coal contracts, and constraints to increased coal production; an overview of coal cleaning technologies; and a comparison of the environmental effects of various SO₂ control methods. Brief summaries of the major findings are presented in this section as background for the conclusions and recommendations.

Summary of Major Findings

Coal Cleanability

The potential for coal cleaning as an SO₂ emission control technique depends upon the coal cleaning processes employed and upon the characteristics of the coal being cleaned. In order to estimate the cleanability of the entire U.S. coal reserve base, many coal cleaning processes must be considered with respect to specific coal properties. To accomplish this a computer model was developed which combines three sets of coal data and allows a variety of analyses to be performed on the resultant data base. The model is called the Reserve Processing Assessment Model (RPAM).

The data base is composed of an overlay of the reserve base of U.S. coal, washability data for coal from sample mines, and approximately 50,000 detailed sample coal analyses. All three sets of data were obtained from the U.S. Bureau

of Mines or Department of Energy in the form of computer tapes. The resulting overlay contains 36,000 coal resource records which have the following information for each:

- Region, state, county, and bed
- Weight in tons of both strip and underground coal
- Mean percent by weight of ash, organic sulfur, and pyritic sulfur
- Mean heat content expressed in Btu/lb
- The float-sink distribution of the mined coal at different media densities.

From this consolidated data base the effects of a coal cleaning process on the reserve resources can be calculated. The coal cleaning process specified can be real or hypothetical, physical or chemical processes.

Programs were written to permit various analyses to be made on the combined data base. These permitted:

- Calculation of the quantities of coal which could be upgraded to be in compliance with various fixed-limit SO₂ emission standards through coal cleaning by various processes. The results were obtained on a regional basis, and they include consideration of sulfur-content variability.
- Calculation of the quantities of coal which could be produced by different coal cleaning processes to meet standards which require removal of a stated percentage of the sulfur in the raw coal. These calculations were done by region and for various emission-averaging times to reflect sulfur variability.
- Calculation of quantities of coal which could be burned in compliance with various percentage-removal standards using combined coal cleaning and flue gas desulfurization (FGD). The results were presented as a function of the FGD removal efficiency required. The results show, for example, that for 13 percent of the coal in the Northern Appalachian Region, a simple cleaning process consisting of crushing to 1.5 inch top size and separation at 1.6 specific gravity would allow the FGD system to operate at only 80 percent sulfur removal efficiency and still meet a 90 percent removal standard. Similarly, 45 percent of the coal of that region could be

used with FGD operating at 85 percent removal efficiency to meet the same standard.

- Calculation of the SO_2 reduction which would be achieved if all of the coal produced annually were cleaned before combustion. The cleaning process assumed was 3/8-inch top size separated at 1.3 specific gravity followed by separation of the refuse at 1.6 specific gravity with combination of the two float fractions. The calculations were done on a state-by-state basis. The results show that a 32.4 percent reduction in national SO_2 emissions could be achieved, at a Btu loss in cleaning of only 3 percent, if all coal in the reserve base were cleaned by this process.

Coal Availability

Existing coal-fired facilities must meet SO_2 emission standards prescribed by the states in the State Implementation Plans (SIP's). The SIP's for SO_2 vary widely from state to state and often within a state. Coal fired electric utility boilers built since 1971 must meet the New Source Performance Standards (NSPS) of $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$. An evaluation of the usefulness of coal cleaning in providing compliance coal must consider not only the cleaning characteristics of coal produced in different regions but also the amounts of coal required by facilities under each of the various SIP regulations. A procedure was developed for making such an evaluation. A computer file was developed to store data on existing utility and industrial energy demand in which each facility was classified by state, actual SIP requirement, capacity, and fuel. The location, capacity, and fuel data for utility boilers were obtained from EPA's Energy Data Systems (EDS) file, and the corresponding information for industrial facilities was obtained largely from the Federal Energy Administration (FEA) survey of "Major Fuel Burning Installations" (MFBI). The assignment of the SIP regulation applicable to each facility was accomplished through a separately constructed matrix relating ZIP code and SIP regulations.

A "coal use" model was developed which relates the energy requirement taken from the facilities file to the quantities of raw coal in the reserve and to the quantities of coal that could be made available by application of various coal cleaning processes to meet the prescribed SO_2 emission standards. The coal quantities were obtained from the RPAM model. The analysis was done by

region, with facilities in a region using coal produced in the same region, and for the entire United States. The model produced, for each SIP range, the ratio of the total amount of compliance coal in the reserve, either raw or cleaned by one of eight processes, to the current annual demand. This ratio is, in effect, the years of availability of compliance coal for each SIP at the current annual rate of consumption.

As an example of the results obtained, four bar charts are shown in Figure 1 for facilities in the northeastern U.S. using coal from the Northern Appalachian Region. In each chart the ratio of total coal to annual demand (or years of availability) is plotted against annual demand. The width of each bar represents the aggregate demand of all facilities in the region which operate under SIP's in the range shown at the top of the bar, while the height of the bar represents the number of years that compliance coal would be available if used at the current rates. The area of each bar represents the total quantity, in 10^{15} Btu, of coal in the reserves of the Northern Appalachian Range which can satisfy the SIP's in the indicated range. The horizontal dotted line shows the years of coal availability, at the current rates, if used without regard to sulfur content, and the area under the dotted line represents the total Btu's of coal in the Northern Appalachian reserve.

The four bar charts show the results for raw coal and for coal produced by three cleaning processes defined as follows:

- (a) Physical coal cleaning using 1-1/2-inch coal separated at 1.6 s.g. (specific gravity).
- (b) Physical coal cleaning using 3/8-inch coal separated at 1.6 s.g. if this produced coal to meet the standard; otherwise, separation at 1.3 s.g. was used. An operating penalty of 1 percent energy use in the cleaning process was assumed.
- (c) Meyers process: for raw coal with greater than 0.2 percent pyritic sulfur, the level of pyritic sulfur is reduced to 0.2 percent. No sulfur reduction takes place if the raw coal pyritic sulfur level is less than 0.2 percent. A 5 percent energy loss was assumed plus an operating penalty of 2 percent energy loss and a weight loss of 10 percent.

The charts show clearly the usefulness of these coal cleaning processes in producing coal to satisfy SIP's or 1971 NSPS. The chart for raw coal shows that no coal in the region could be burned in compliance with a SIP of 0.32 (New Jersey, industrial, metropolitan areas), and only limited quantities

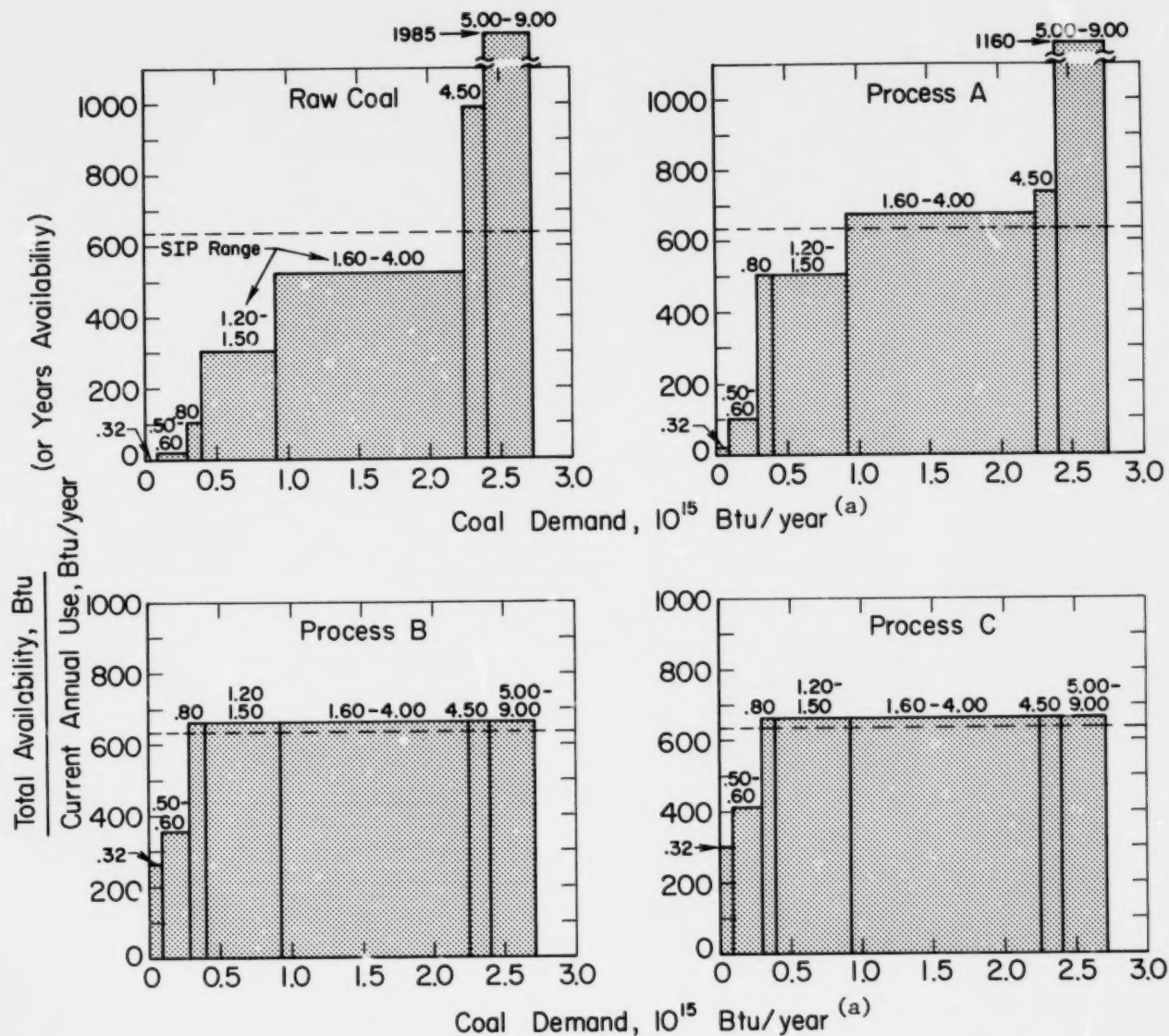


FIGURE 1. INCREASE IN THE QUANTITIES OF SIP-COMPLIANCE COAL ACHIEVABLE BY COAL CLEANING (see text for definition of processes)

(a) Northeast U.S. utility and industrial coal demand met by coal produced in the Northern Appalachian region.

of raw coal are sufficiently low in sulfur content that SIP's of 0.5 to 0.8 could be met. On the other hand, the charts for coal cleaned by Processes A, B, and C show progressively increasing quantities (increases in the shaded areas) of coal in compliance with low SIP's which can be produced by these cleaning processes. Results of this type were produced for eight real or hypothetical coal cleaning processes, for six regions, and for the entire United States. These results show how valuable coal cleaning is as a means of satisfying SIP regulations and 1971 NSPS.

Cost Comparisons

A comparative analysis was conducted of the current technologically feasible SO₂ emission control methods: naturally occurring low-sulfur coal, FGD, PCC, and the combined use of FGD and PCC. The procedure utilized has been (1) to compare and analyze the results of previous studies; (2) to utilize these results and comparisons to develop further more nearly accurate, reliable estimates of direct costs and benefits; and then (3) to evaluate the influence of the performance of complete energy conversion systems on the cost and attractiveness of the competing control methods.

In addition to the costs associated with each technology which are traditionally included in a cost analysis, emphasis was placed in this work on identifying and quantifying the benefits of coal cleaning. In the past, these benefits have been largely ignored in comparative cost analyses. The benefits attributed to burning clean coal are as follows: (1) transportation costs are reduced because less coal is shipped due to the increased heating value; (2) ash disposal costs for the utility are decreased; (3) coal pulverizing costs are reduced; (4) benefits paid to the mine operations Pension and Benefit Trust Fund are reduced because fewer tons of coal are shipped from the mine to equal the same heating value; and (5) power plant maintenance costs are reduced by using coal with lower ash and sulfur content. Other indirect benefits to the power plant associated with burning clean coal result from increased boiler efficiencies, longer plant life, and increased boiler availability.

In the event of a combined emission control system of physical coal cleaning and flue gas desulfurization, it becomes necessary to determine the effects of physically cleaned coal on the FGD system. The benefits to the FGD system result from less flue gas to be treated and, consequently,

units of smaller size and capacity can be used. Therefore, there will be reduced costs for energy, labor, chemicals, maintenance, supplies, overhead, working capital, sludge disposal, and land requirements for both the scrubber system and sludge disposal system.

For this analysis a single-unit power plant with a nominal capacity of 500 MW was selected. For each alternative SO₂ control method, the system performance, availability, and costs were evaluated. A summary of the costs is presented in Table 1.

The results show that, when all costs and benefits to utilities of using physical coal cleaning are properly evaluated, physical coal cleaning has a definite economic superiority, even if supplemental application of another method, FGD, must be used to achieve full compliance with applicable NSPS or SIP emission limits.

Inspection of the total cost column of Table 1 reveals some interesting specific points. First of all, the systems which include coal cleaning provide the least cost methods of producing electricity. Comparison of the two systems not providing sufficient control to meet 1971 NSPS, Cases 1 and 3, shows that physical coal cleaning of the fuel provides for an overall lower cost of generation than does the use of raw coal (about 2.4¢/kWh versus about 2.5¢/kWh). This results despite the cleaning costs and the loss of some Btu's, because of the greater, more efficient utilization of the generation facility and a consequent lower fixed charge per kWh generated.

Second, for the systems which achieve full compliance with 1971 NSPS, the two cases which incorporate physical coal cleaning with FGD are by far more economical (about 3.0¢/kWh for both Cases 5 and 6 and about 3.5¢/kWh for Case 4 for FGD alone).

Finally, the example shown for the use of low-sulfur western coal (Case 2) indicates no cost benefit in comparison with any other case except Case 4, i.e., FGD not in combination with physical coal cleaning. The cost here is about 3.3¢/kWh for Case 2 versus about 3.5¢/kWh for Case 4. This result tends to confirm the conclusion made by some utilities that the use of low-sulfur western coal to achieve compliance with the 1971 NSPS would cost less than the use of FGD.

In summary, the use of physical coal cleaning with FGD is significantly more attractive economically in the examples presented than either FGD alone

TABLE 1. SUMMARY OF COSTS FOR POWER GENERATION USING VARIOUS CONTROL MODES

Number	Case Description	Emission Regulations Met	Operating Hours per Year (b)	Power Plant Costs, c/kwh			FCD Costs, c/kwh			Coal Cleaning Costs and Savings, c/kwh			Total Costs, c/kwh
				Fixed	Fuel	Production	Incremental Maintenance	Fixed	OGM	Fixed	OGM	PCC Savings	
1 (a)	Raw high-sulfur eastern coal, no FGD (baseline)	None	7008	1.446	0.840	0.148	0.093	--	--	--	--	--	2.527
2	Raw low-sulfur western coal, no FGD	NSPS (c)	6132	1.652	1.410	0.248	--	--	--	--	--	--	3.310
3 (a)	Cleaned high-sulfur eastern coal, no FGD	Various SIP's	7884	1.285	0.898	0.158	0.015	--	--	0.041	0.089	-0.041	2.445
4	Raw high-sulfur eastern coal, with FGD (4 modules + 1 spare) (Boiler = 0.8, FGD = 0.65/module)	NSPS (d)	5493	1.845	0.840	0.148	0.093	0.389	0.230	--	--	--	3.545
5	Cleaned high-sulfur eastern coal, with FGD (3 modules + 1 spare) (Boiler = 0.9, FGD = 0.75/module)	NSPS (d)	7061	1.435	0.898	0.158	0.015	0.270	0.230	0.046	0.089	-0.041	3.069
6	Cleaned high-sulfur eastern coal, with FGD (3 modules + 2 spares) (Boiler = 0.9, FGD = 0.75/module)	NSPS (d)	7569	1.339	0.898	0.158	0.015	0.282	0.230	0.043	0.089	-0.041	2.982

(a) Not in compliance with NSPS promulgated December 23, 1971 (36FR24876).

(b) Based on postulated availabilities.

(c) Only 1971 NSPS calling for maximum emissions of 1.2 lb SO₂/10⁶ Btu.(d) Either 1971 or 1979 NSPS, but greater scrubber capability would be needed to meet the 1979 NSPS. Differences in costs of scrubbers to achieve higher SO₂ removals have been ignored. A more rigorous treatment has been provided by Kilgroe(2-1).

or western low-sulfur coal. It is very evident, also, that in any case where physical coal cleaning alone will permit compliance with 1971 NSPS or with state implementation plans, its use will provide the lowest cost solution. However, in any specific case, the comparisons must be evaluated independently to account for site-specific variables such as coal composition, transportation requirements, and plant utilization.

Barriers to Expanded Coal Cleaning

A number of factors which might inhibit expansion of the use of coal cleaning were examined. The common theme encountered is that of uncertainty. Investments in coal cleaning facilities may be deferred because of uncertainty regarding technical details, emission limits or other environmental regulations, or the ultimate profitability of the investment. The general types of barriers and a brief listing of examples of each are summarized below.

(a) Technical

- Data needed to relate washability results to commercial plant performance are lacking.
- Improved quality control techniques are needed.
- Better techniques for separation of fine pyrite need to be developed and proven.
- More extensive data on benefits accruing to a boiler burning cleaned coal need to be obtained.

(b) Environmental

- Solid waste disposal requires control of leaching, fugitive dust emissions, and fires.
- Trace elements are concentrated in the refuse, a benefit with respect to the clean coal product, but they require careful waste disposal.
- Land-use options in the immediate area of the cleaning plant are restricted.

(c) Transportation

- Increased coal use will place stress on the transportation system.
- Coal cleaning will help in mitigating transport problems because of the higher Btu content per unit weight of cleaned coal.

- However, accelerated use of coal cleaning could add to the problem in certain areas in which cleanable coals predominate. For example, traffic from the Appalachian region to the middle Atlantic states would be expected to increase disproportionately as coal cleaning expands.
- (d) Institutional
- PCC benefits may not be fully appreciated by potential investors.
 - Commercial practicality of coal cleaning as a sulfur removal strategy may not be viewed as adequately demonstrated.
 - Uncertainty exists regarding the Public Utility Commission's attitude toward allowing fuel cost pass-through if a utility were to invest in coal cleaning facilities.
- (e) Economic and Social
- Coal cleaning does not now qualify for tax purposes as a pollution control investment.
 - Investment in coal cleaning may be deferred because of the possibility that, to increase production of indigenous high-sulfur coals, SIP's may be made less stringent. This would reduce the markets for cleaned coal.
 - Capital may be difficult to raise because of the lack of information on commercial coal cleaning operations.
- (f) Regulatory and Legislative
- Uncertainties exist regarding enforcement of SIP's, averaging periods, and variances.
 - Uncertainties exist surrounding the permanence of any SO₂ emission standard.
 - Uncertainties exist regarding air and water pollution standards for coal cleaning plants.
 - Uncertainties exist concerning legislative incentives for the industrial use of coal.

Conclusions

Coal cleaning is an effective, efficient, and economical SO₂ emission control technique. Accelerated development and expanded deployment of the technology must be instituted.

- Physical coal cleaning is the least-cost method of reducing sulfur emissions from the combustion of coal.
- Coal cleaning, with the proper selection of sources and users, can produce coal which can be burned in compliance, over a period of almost 200 years, with SIP's and with 1971 NSPS without additional control.
- The quantity of compliance coal can be increased substantially by coal cleaning. For example, in the eastern midwest region the amount of compliance coals capable of meeting SIP requirements in the range of 3 to 6 lb SO₂/10⁶ Btu can be doubled by the use of physical cleaning techniques.
- Coal cleaning followed by flue gas desulfurization can be an attractive strategy for meeting the percentage removal requirements of the 1979 NSPS. Because credit is allowed for sulfur removal prior to combustion, cleaning would permit the scrubber to operate at a lower, more readily achievable, sulfur-removal efficiency and still achieve the required percentage sulfur removal.
- Preliminary data indicate that coal cleaning reduces the variability of sulfur in the product coal. If this is substantiated, cleaned coal would be preferred over raw coal. Reduced variability would allow scaling down of FGD capacities designed to take sulfur variability into account in meeting a percentage reduction.
- Cleaned coals have lower concentrations of many of the trace elements because of selective concentration in the refuse component.
- Substantial attendant benefits of coal cleaning include reduced transportation costs, reduced boiler maintenance costs, reduced ash disposal costs, and enhanced boiler availability. When all

of the benefits are quantified for a given facility, the net cost of coal cleaning will be less than zero in many cases.

- Many of the barriers to increased use of coal cleaning are due to uncertainties regarding technical questions, the level and type of environmental regulations (now and in the future), and the profitability of investment in coal cleaning.

Recommendations

This study leads to two basic conclusions: first, that widespread use of physical coal cleaning would benefit the entire nation, and second, that action by the Federal government is the only way to remove the barriers blocking expanded use of this method of sulfur control. Recommendations for technical research and development and for coal cleaning policy are based on these conclusions.

Recommended Research and Development

Although coal cleaning has been employed for years for ash removal and for Btu enhancement, its use specifically to remove sulfur is new. Adequate ash removal technology exists, but coal cleaning for sulfur removal remains an art which must be advanced by applying and improving the present technology to establish proven plant designs for sulfur removal. The non-uniform nature of coal underlies the major technical problems to be overcome. As coal characteristics differ, their separation properties differ, and so does the optimum approach to cleaning. In the technical area, EPA and/or DOE should initiate the following research and development programs.

- (1) Coal Washability Data. Ongoing experimental determinations directed at obtaining additional data on coal washability must be greatly accelerated and expanded. The washability data available now are extremely limited in comparison to the untested reserves. Additional data are required because results from one seam cannot be applied to another. Correlational techniques should be further explored in an effort to minimize the experimental data needed for each seam.

- (2) Equipment Performance Correlations. Correlations of performance for individual items of equipment are needed to permit optimum design and control of cleaning plants. Such correlations can be obtained only by analysis of experimental performance data recorded under a variety of conditions with many different coals. Much of the experimental data still need to be obtained.
- (3) Plant Simulation Model. A comprehensive coal cleaning plant simulation model would permit the optimization of plant designs and plant operations. This model, when computerized, must be capable of processing inputs concerning a broad range of coal characteristics, the range of cleaning techniques available, the performance of individual types of equipment when presented with different coals (as exemplified by their washability), and costs of various plant designs.
- (4) Advanced Separation Techniques. Development of advanced separation designed specifically for sulfur removal must be accelerated—including research on fine and ultrafine particle separation and on chemical cleaning techniques for organic sulfur removal. The goal of these developments must be maximum sulfur removal at a specified cost or minimum cost at a specified level of sulfur removal.
- (5) Process Control System and Sensor Development. Systems for the control of cleaning plant product quality must be developed. Sensors and control systems are both necessary. Sensors detecting changes in feed coal characteristics and product coal quality should provide inputs to the control system, perhaps based on the computer simulation model, so that equipment control set points would be changed. These changes in set points would be designed to moderate product quality variations.

- (6) Test Facilities. Commercial coal cleaning test facilities should be built to develop advanced separation techniques and flow circuits. Analysis of the equipment and circuit performance at these plants will provide much needed engineering and cost data.
- (7) Variability of Sulfur in Coal. Studies should be conducted for the determination of the sulfur variability in product coal as compared with the feed coal. Using these collected data, statistical studies must be performed so that intelligent selection can be made of sulfur levels of coal to be burned in relation to the emission levels permitted. Two candidate statistical approaches, traditional and geo-statistics, giving contrasting results, are currently available for study.
- (8) Boiler Performance Data. Existing data must be collected and additional experimental data must be generated on the effects of cleaned coal combustion on boiler performance. Only through the analysis of such data may the potential benefits accruing from the burning of cleaned coal on boiler availability, maintenance, capacity, efficiency, etc., be evaluated.
- (9) Environmental Control. Demonstrations of acceptable practices for solid waste disposal and for the control of pollutants in water effluents are needed. Few data are available on trace elements migration and control and on infiltration of pollutants into groundwater. The development of acceptable practices and their demonstration in conjunction with plant demonstrations should be accomplished.

Recommended Policy Approaches

In order to promote widespread use of coal cleaning, the Federal Government could adopt one of the following approaches:

Policy A: Establish policies to provide growth in the use of coal cleaning by assuring that the technology is competitive in the U.S. marketplace and by assuring coal users that it is a sound investment.

Policy B: Or, as an alternative, establish a policy to require that that all coal be cleaned before it is burned anywhere in the United States.

Policy A. Assuming a successful outcome of the technical initiative just outlined, the private sector will make investment decisions on the basis of "bottom-line" economics. In general, the institutional, legislative, and regulatory barriers identified in Section 8 are barriers because they have an impact on the economics. Therefore, a policy to assure competitiveness is needed to promote rapid deployment of the technology.

Initiatives designed to implement Policy A could include the following.

- (1) Promote Regulation Stability. Federal and state EPA's could remove the uncertainties regarding both SO₂ emission regulations and environmental regulations pertaining to coal cleaning plants. The private sector could then make investment decisions based on known costs of compliance without fear that future changes would cause the investment to become unprofitable.
- (2) Provide EPCA Loan Guarantees. The Federal government could provide loan guarantees under Section 102 of the Energy Policy and Conservation Act (EPCA) for building centralized coal cleaning facilities to be used for processing the output of many small coal producers.
- (3) Appropriate Plant Construction Funds and Permit Management-Fee Plant Operation. Congress could appropriate funds to construct coal cleaning plants to be operated by industry on a management-fee basis in a manner similar to that used by the Reconstruction Finance Corporation in the building of synthetic rubber plants during World War II. Provision could be made for the private sector to buy the plants once profitable commercial operation is demonstrated.
- (4) Reduce Tax or Subsidize. Congress could legislate provisions for a lower income tax rate or for direct subsidies based on the percent of sulfur removed prior to the sale of the coal.
- (5) Permit Pollution Control Investments for Tax Purposes. The Internal Revenue Service--through Congressional intervention if necessary--could reverse

their position so that coal cleaning plants would qualify as pollution control investments for tax purposes. Arguments for revision can be based on EPA's move to credit precombustion sulfur removal toward an SO₂ percentage removal standard.

- (6) Allow Unit Train Rates for Rail Shipment. ICC regulations could be changed to allow rail shipment of cleaned coal at the same rates as uncleaned coal.
- (7) Establish Public Information Program. EPA should create a task force to establish a top-notch public information program to educate utilities and potential industrial users about the benefits of burning cleaned coal.

Policy B. As an alternative to Policy A, Policy B would require all coal to be cleaned prior to combustion. Congressional action would be necessary to mandate nationwide coal cleaning, of course. Coal cleaning as now practiced could be used in the implementation of this policy. However, the full benefits of coal cleaning in reducing sulfur dioxide emissions and in achieving saving in electric power generation costs will be realized only after the recommended research and development programs are successfully completed and the results used to optimize the design and operation of coal cleaning plants.

Either policy has merit on several grounds.

- (1) Low Cost. Physical coal cleaning is the least-cost method for reducing SO₂ emissions.
- (2) Quick Results (No Retrofitting). Cleaned coal could be used immediately in all existing facilities. There are essentially no "retrofit" problems. Thus, decreased SO₂ emissions can be achieved as soon as cleaned coal becomes available. In contrast, the NSPS for coal fired boilers will not materially affect total SO₂ emissions until a significant fraction of existing boilers are retired and replaced.
- (3) Significantly Reduced SO₂ Emissions. State-of-the-art (ash removal) cleaning methods could reduce uncontrolled emissions of SO₂ from coal-burning facilities by an estimated 32 percent if all coal were cleaned. Even greater reductions would be

anticipated as economically feasible advanced processes capable of removing organic sulfur are developed. Scrubbers, operating at 85 percent sulfur-removal efficiency, would have to be installed on 38 percent of the entire coal-burning capacity to achieve an equivalent reduction in SO₂ emissions.

- (4) Extended Boiler Life, Etc. The use of cleaned coal is expected to extend boiler life, improve efficiency, and increase the capacity factor--all significant conservation, operation, and cost benefits.

Reference for Section 2

- (2-1) Kilgroe, James D., "Combined Coal Cleaning and FGD", Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, Presented at: Symposium on Flue Gas Desulfurization, Las Vegas, NV, March 1979.

SECTION 3

COAL DATA SUMMARY

As background information, this section presents pertinent data on coal production and use.

Coal Production and Coal Characteristics

Data for the 1975 levels of coal production are compiled in Appendix A. Data are given by state and county for the eastern and western regions of the United States. The total coal production in the eastern states in 1975 was 537.5 million short tons, with West Virginia, eastern Kentucky, Pennsylvania, Illinois, western Kentucky, and Ohio being the largest producers, in that order. The total coal production for the western states in 1975 was 110.9 million tons. The largest producers were Wyoming, Montana, Texas, New Mexico, and Colorado, in that order. The U.S. total production was 648.4 million tons.

The average values of sulfur content, ash content, and calorific content by state and county are included in the tables in Appendix A. Further, the distribution of sulfur content range of coal produced in each state in 1975 is given also in Appendix A. The eastern region produced 153 million tons of coal, 28 percent of the production, with less than 1 percent sulfur. Another 29 percent of eastern production contained sulfur in the range of 1.00-2.19 percent; 16 percent contained 2.20-3.39 percent sulfur; and 16 percent contained more than 3.40 percent sulfur. The sulfur content was unknown for 11 percent of the coal produced. In the western region, 50 percent of the coal produced contained less than 1 percent sulfur, 36 percent had sulfur values in the range 1.00-1.19, while 11 percent had an unknown sulfur content.

Projections of coal production through 1985 are given in Appendix A for three growth scenarios. Projected production in 1985 varies from 953 to 1,553 million tons. A discussion of the growth scenarios and their comparisons with other projections is included.

Possible constraints to achieving the higher levels of coal production projected are discussed in Appendix B. Constraints considered include the time required for new mine openings, availability of mining personnel, availability of mining equipment, financing considerations, and adequacy of transportation. Producers believe that 1975 production could be doubled by 1985 and tripled by 2000 if the demand, in fact, requires such production increases.

Coal Use

The pattern of coal use by various consuming sectors and by region of the country is shown in Table 2 for 1974. Exports, railroad fuel, and coal used at mines or sold to employees are not included in the tables. The electric utility sector was the largest consumer of coal followed by coke ovens and industrial, which is included in the "all others" category.

The average sulfur content of the coal used by different consuming sectors in 1974 is shown in Table 3 by region of origin. The total coal shipped from each region for which sulfur content was reported is included in Table 3. The overall average sulfur content for all sectors was 2.2 percent with the utility and industrial sectors average values somewhat higher, and coking coal considerably lower at 1.0 percent.

Coal Reserves

A summary of the demonstrated coal reserve base of the United States on January 1, 1974, is given by state in Tables 4, 5, and 6 for underground mining, for surface mining, and for the total of underground and surface mining, respectively. The sulfur content of each of these reserves also is shown in these three tables. As noted in the tables, these data were developed by the U.S. Bureau of Mines. Recently, questions have been raised regarding

TABLE 2. 1974 COAL USE BY CONSUMING SECTOR AND BY REGION, 10³ TONS (3-1)

Region	Total	Consuming Sector			All Others (a)
		Electric Utilities	Coke and Gas Plants	Retail Dealers	
New England	2,055	1,827	--	29	199
Middle Atlantic	81,122	44,412	28,515	363	7,832
East North Central	194,202	130,380	33,871	3,016	26,935
West North Central	43,966	37,725	1,015	646	4,580
South Atlantic	97,804	76,977	8,776	1,411	10,640
East South Central	71,080	55,720	8,229	547	6,584
West South Central	8,894	5,426	878	4	2,586
Mountain	34,972	29,336	3,020	510	2,106
Pacific	6,500	3,890	2,148	20	442
Alaska	690	262	--	12	416
Grand Total	541,285	385,955	86,452	6,558	62,320

(a) Includes Industrial.

TABLE 3. AVERAGE SULFUR CONTENT OF COAL BY CONSUMING
SECTOR AND BY REGION OF ORIGIN, 1974⁽³⁻¹⁾

Region of Origin	Average Sulfur Content, %					Total Quantity Shipped, 10 ⁶ tons ^(a)
	Electric Utilities	Coke and Gas Plants	Other Industrial Uses and Retail Dealers	All Other Uses	Total	
Eastern Pennsylvania	2.2	1.0	1.9	2.4	2.0	37.9
Western Pennsylvania	2.1	1.5	2.1	1.7	1.7	26.9
Northern West Virginia	2.9	1.4	2.4	2.0	2.6	24.6
Ohio	3.6	-	3.2	3.1	3.5	40.0
Panhandle	3.9	-	2.9	3.1	3.8	7.0
Southern #1	0.6	0.6	0.8	0.7	0.7	16.7
Southern #2	1.1	0.8	0.9	1.0	1.0	69.2
West Kentucky	3.9	-	3.0	1.4	3.9	50.7
Illinois	3.2	0.9	2.9	3.6	3.1	57.9
Indiana	3.5	-	3.3	3.6	3.4	23.5
Iowa	3.3	-	3.0	3.0	3.3	0.5
Southeastern	1.6	1.0	2.2	0.7	1.4	14.3
Arkansas-Oklahoma	-	1.8	2.3	0.9	1.6	0.6
Southwestern	2.8	0.5	2.0	2.8	2.8	14.6
Colorado	0.5	0.6	0.6	0.4	0.5	7.2
New Mexico	0.6	-	0.8	0.8	0.6	14.9
Wyoming	0.5	0.9	0.7	0.8	0.6	20.3
Utah	0.6	0.9	0.6	0.7	0.7	5.9
North/South Dakota	0.8	-	0.7	0.7	0.8	7.3
Montana	0.7	-	0.8	0.9	0.7	14.1
Washington	0.5	-	0.2	-	0.5	4.6
Total United States	2.4	1.0	2.3	1.8	2.2	458.8

(a) Data from producers reporting sulfur content (76 percent of total U.S. production).

TABLE 4. DEMONSTRATED COAL RESERVE BASE OF THE UNITED STATES
ON JANUARY 1, 1974, BY UNDERGROUND METHOD OF MINING(3-1)
(Million tons)

State	Sulfur range, percent				Total ¹
	<1.0	1.1-3.0	>3.0	Unknown	
Alabama	589.3	1,016.7	14.8	176.2	1,798.1
Alaska	4,080.8	163.2	--	--	4,246.4
Arkansas	43.3	310.3	29.2	19.1	402.4
Colorado	6,751.3	640.0	47.3	6,547.3	13,999.2
Georgia	.3	--	--	.2	.5
Illinois	1,034.7	5,848.4	33,647.6	12,908.4	53,441.9
Indiana	443.5	2,746.6	4,355.1	1,402.5	8,948.5
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kentucky, East	5,042.7	2,391.9	212.7	1,814.0	9,466.5
Kentucky, West	--	386.6	7,226.4	1,107.1	8,719.9
Maryland	106.5	623.9	171.2	--	901.9
Michigan	4.6	84.9	20.8	7.0	117.6
Missouri	--	134.2	3,590.2	2,350.5	6,073.6
Montana	63,464.2	1,939.8	456.2	--	65,834.3
New Mexico	1,894.3	214.1	.9	27.5	2,136.5
North Carolina	--	--	--	31.3	31.3
Ohio	115.5	5,449.9	10,109.4	1,754.1	17,423.3
Oklahoma	154.5	238.5	202.6	264.3	860.1
Oregon	1.0	--	--	--	1.0
Pennsylvania	7,179.7	16,195.2	3,568.1	2,864.8	29,819.2
Tennessee	139.3	370.0	101.4	53.9	667.1
Utah	1,916.2	1,397.6	6.8	460.3	3,780.5
Virginia	1,728.5	945.4	12.0	283.3	2,970.7
Washington	431.0	957.8	13.2	42.9	1,445.9
West Virginia	11,086.6	12,583.4	6,552.9	4,142.9	34,377.8
Wyoming	20,719.5	4,535.1	1,275.6	2,955.0	29,490.8
Total ¹	126,928.8	59,400.2	73,720.2	39,761.6	299,839.7

¹Data may not add to totals shown because of independent rounding.

TABLE 5. DEMONSTRATED COAL RESERVE BASE OF THE UNITED STATES
ON JANUARY 1, 1974, BY SURFACE METHOD OF MINING(3-1)
(Million tons)

State	Sulfur range, percent				Total ¹
	<1.0	1.1-3.0	>3.0	Unknown	
Alabama	35.4	83.2	1.6	1,063.2	1,183.7
Alaska	7,377.6	21.0	--	--	7,399.0
Arizona	173.3	176.7	--	--	350.0
Arkansas	37.9	152.8	17.1	55.2	263.3
Colorado	724.2	146.2	--	--	870.0
Illinois	60.4	1,493.0	9,321.3	1,347.8	12,222.9
Indiana	105.3	559.2	907.3	101.6	1,674.1
Kansas	--	309.2	695.6	383.2	1,388.1
Kentucky, East	1,515.7	929.9	86.8	915.3	3,450.2
Kentucky, West	.2	177.8	2,017.5	1,708.8	3,904.0
Maryland	28.6	66.6	16.2	34.6	146.3
Michigan	--	.5	.1	--	.6
Missouri	--	47.8	1,635.8	1,730.0	3,413.7
Montana	38,182.4	2,175.2	46.4	2,166.7	42,561.9
New Mexico	1,681.0	579.3	--	--	2,258.3
North Carolina	--	--	--	.4	.4
North Dakota	5,389.0	10,325.4	268.7	15.0	16,003.0
Ohio	18.9	991.0	2,524.9	117.9	3,653.9
Oklahoma	120.5	88.1	38.8	186.2	434.1
Oregon	.5	.3	--	--	.8
Pennsylvania	138.6	718.4	231.5	89.5	1,181.4
South Dakota	103.1	287.9	35.9	1.0	428.0
Tennessee	65.5	163.2	55.2	34.1	319.6
Texas	659.8	1,884.6	284.1	444.0	3,271.9
Utah	52.3	149.1	42.6	18.0	262.0
Virginia	411.6	218.1	2.1	46.7	679.2
Washington	172.5	307.7	25.8	2.2	508.1
West Virginia	3,005.5	1,422.8	270.4	509.6	5,212.0
Wyoming	13,192.8	10,122.3	425.5	105.3	23,845.3
Total ¹	73,252.3	33,597.4	18,950.9	11,076.1	136,885.7

¹ Data may not add to totals shown because of independent rounding.

TABLE 6. DEMONSTRATED COAL RESERVE BASE OF THE UNITED STATES
ON JANUARY 1, 1974, TOTAL UNDERGROUND AND SURFACE⁽³⁻¹⁾
(Million tons)

State	Sulfur range, percent				Total ¹
	<1.0	1.1-3.0	>3.0	Unknown	
Alabama	624.7	1,099.9	16.4	1,239.4	2,981.8
Alaska	11,458.4	184.2	--	--	11,645.4
Arizona	173.3	176.7	--	--	350.0
Arkansas	81.2	463.1	46.3	74.3	665.7
Colorado	7,475.5	786.2	47.3	6,547.3	14,869.2
Georgia	.3	--	--	.2	.5
Illinois	1,095.1	7,341.4	42,968.9	14,256.2	65,664.8
Indiana	548.8	3,305.8	5,262.4	1,501.1	10,622.6
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kansas	--	309.2	695.6	383.2	1,388.1
Kentucky, East	6,558.4	3,321.8	299.5	2,729.3	12,916.7
Kentucky, West	.2	564.4	9,243.9	2,815.9	12,623.9
Maryland	135.1	690.5	187.4	34.6	1,048.2
Michigan	4.6	85.4	20.9	7.0	118.2
Missouri	--	182.0	5,226.0	4,080.5	9,487.3
Montana	101,646.6	4,115.0	502.6	2,166.7	108,396.2
New Mexico	3,575.3	793.4	.9	27.5	4,394.8
North Carolina	--	--	--	31.7	31.7
North Dakota	5,389.0	10,325.4	268.7	15.0	16,003.0
Ohio	134.4	6,440.9	12,634.3	1,872.0	21,077.2
Oklahoma	275.0	326.6	241.4	450.5	1,294.2
Oregon	1.5	.8	--	--	1.8
Pennsylvania	7,318.3	16,913.6	3,799.6	2,954.2	31,000.6
South Dakota	103.1	287.9	35.9	1.0	428.0
Tennessee	204.8	533.2	156.6	88.0	986.7
Texas	659.8	1,884.6	284.1	444.0	8,271.9
Utah	1,968.5	1,546.7	49.4	478.8	4,042.5
Virginia	2,140.1	1,163.5	14.1	330.0	3,649.9
Washington	603.5	1,265.5	39.0	45.1	1,954.0
West Virginia	14,092.1	14,006.2	6,823.3	4,652.5	89,589.8
Wyoming	33,912.3	14,657.4	1,701.1	3,060.3	53,336.1
Total ¹	200,181.1	92,997.6	92,671.1	50,837.7	436,725.4

¹Data may not add to totals shown because of independent rounding.

the validity of the data base on coal reserves. Project staff consulted directly with Bureau of Mines personnel associated with the development of the reserves data and determined that revisions are not expected to result in major changes in the data.

The complete Bureau of Mines coal reserves data file was acquired by Battelle in the form of a computer tape. This file contains reserve data by county.

Coal Cleanability

The cleanability of the U.S. coal reserve base by major coal-producing region has been estimated for examples of physical and chemical coal cleaning processes. The regions considered are:

- (1) Northern Appalachia
- (2) Southern Appalachia
- (3) Alabama
- (4) Eastern Midwest
- (5) Western Midwest
- (6) Western
- (7) Entire U.S.A.

Two regions were omitted for lack of appropriate data--the Alaskan reserves and Pennsylvania anthracite reserves. The methodology used to assess the cleanability of the reserves, known as the Reserves Processing Assessment Model (RPAM), is discussed in detail later in the section (following Figure 13). The RPAM methodology is applicable also to analysis of the reserves by state and by county but, to date, has been applied only on a state or regional basis.

The variability of sulfur in a stream of coal from a given mine is taken into account in this work by assuming the maximum coal sulfur emission upon combustion to be

$$e = \mu_c (1 + a_c RSD_c) \quad (1)$$

where μ_c is the maximum allowable mean coal sulfur content for achieving a maximum emission level e with a confidence level given by a_c at a relative standard deviations (RSD_c) from the mean. In this work, a_c was taken to be 2.0 which corresponds to a confidence level of 97.72 percent. The relative standard deviations postulated for eastern and western coals for different averaging periods and for different size boilers are given in Table 7.

Physical coal cleaning processes A1-A4 and chemical coal cleaning processes B1-B4, as follows, were used to assess cleanability.

- A1. PCC 1-1/2 inch, 1.6 s.g. This process separates at 1.6 specific gravity after crushing to 1-1/2 inch top size. No energy penalties are imposed other than those inherent in the separation process.
- A2. PCC 3/8 inch, 1.3 s.g. This process separates at 1.3 specific gravity after crushing to 3/8 inch top size. An operating energy penalty of 1 percent is assumed, in addition to the energy loss inherent in the separation process.
- A3. PCC 1.6 s.g. on sink of PCC 3/8 inch, 1.3. s.g. The sink from the 1.3 specific gravity separation at 3/8-inch top size is further separated at 1.6 specific gravity. This process gives a middling product from the refuse of process A2 and does not include the float from the 1.3 s.g. separation. The operating energy penalty is assumed to be 1 percent on only the 1.3 s.g. separation, in addition to that inherent in the separations.
- A4. Ninety percent pyritic sulfur removal. This process is assumed to remove 90 percent of the pyritic sulfur in the coal while losing 10 percent of the weight and 5 percent of the energy. An additional 2 percent energy loss is assumed as an operating penalty.
- B1. Meyers process. This process reduces the pyritic sulfur content of the coal to a threshold level of

TABLE 7. RELATIVE STANDARD DEVIATIONS POSTULATED FOR
RAW AND WASHED COAL FOR A 75×10^6 BTU/HR
BOILER AND A 600 MW BOILER

Averaging Period, Boiler Size	Relative Standard Deviations			
	Eastern		Western	
	Raw	Washed	Raw	Washed
24-hour averaging, 75×10^6 Btu/hr	0.28	0.10	0.07	0.07
30-day averaging, 75×10^6 Btu/hr	0.19	0.07	0.04	0.04
24-hour averaging, 600 MW	0.19	0.07	0.07	0.07
30-day averaging, 600 MW	0.09	0.04	0.04	0.04

0.2 percent. A 10 percent weight loss and a 5 percent energy loss is assumed in the process as well as a 2 percent energy loss operating penalty.

- B2. Gravichem process. This is a combined physical and chemical cleaning process in which the coal is first crushed to 14 mesh and separated at 1.3 specific gravity. The sink of this separation is then treated with Meyers process and combined with the float. The energy penalties assumed in the process are those due to the separation process and to the penalties assumed in Process B1 for the Meyers treatment of the sink.
- B3. Ninety-five percent pyritic sulfur and 20 percent organic sulfur removed. A weight loss of 15 percent is assumed and an energy loss of 10 percent, together with an operating energy penalty of 2 percent.
- B4. Ninety-five percent pyritic sulfur and 40 percent organic sulfur removed. A weight loss of 25 percent is assumed and an energy loss of 20 percent, together with an operating energy penalty of 3 percent.

The additional operating energy penalties used in these processes are estimates for various energy-consuming operations such as thermal drying of coal, grinding to smaller mesh sizes, etc.

Results

The data file generated in this work can be used to conduct many types of analyses. The results of some pertinent applications are included in the following paragraphs.

An estimate was made of the impact on aggregate SO_2 emissions if all coal were physically cleaned before combustion. The data file used as input to the RPAM model contains reserve data rather than production data; therefore, this estimate was based on the cleanability of the entire reserve base. The cleaning process assumed consists of crushing the coal to 3/8-inch top size with separation at 1.3 specific gravity. The sink from this separation is then separated at 1.6 specific gravity and the float fractions combined. This is, in effect, Process A2 and Process A3 combined. The

RPAM model was used to calculate, on a state-by-state basis, the total SO_2 emissions which would occur if all the coal in the reserve were burned, first without control and then after cleaning by the assumed process. The SO_2 emissions associated with coal from each state were totaled to obtain the aggregate uncontrolled emissions, which were compared with the aggregate emissions after coal cleaning. The result showed that, for the entire U.S. reserve base, SO_2 emissions would be 32.4 percent less if the assumed coal cleaning process were applied to all coal before combustion. Of course, coal production is not conducted uniformly from the entire reserve, and the actual SO_2 reduction achievable by cleaning all the coal burned during any given year would differ from the result obtained, depending upon which coal seams were being produced during that year. Nevertheless, over the long term, the indicated reduction in SO_2 emissions from coal cleaning would be approached. In order to achieve the same degree of reduction in SO_2 emissions by means of flue gas desulfurization, scrubbers operating at 85 percent removal all of the time would have to be installed on 38 percent of the total coal-fired capacity.

Tables 8 and 9 show the percentage of the reserve base, by heat content, that is available on a regional basis to meet emission standards of 516 (1.2), 860 (2.0), 1290 (3.0), and 1720 (4.0) ng/joule ($\text{lb}/10^6$ Btu). It is assumed that prior to combustion the coal has been cleaned by one of the above cleaning processes. For comparison purposes, the percent energy of raw coal that meets these standards is also shown. Values are given both ignoring sulfur variability and averaging sulfur variability over 24 hours and 30 days for a 75×10^6 Btu/hr boiler and a 600 MW boiler, using the relative standard deviations postulated in Table 7 and a_c of Equation 1 set equal to 2.0. For all of the emission standards considered, a floor of 86 ng/joule ($0.2 \text{ lb}/10^6$ Btu) was used; if the emission level of the raw coal is below this floor, then cleaning of the coal was assumed to be unnecessary.

Tables 10 and 11 show, for physical cleaning processes and chemical cleaning processes, respectively, the emission standards that can be set for coal from each region, if it is required that 50 percent or 25 percent of the coal in the region meets the standard after cleaning. The emission standards that are possible depend on the averaging period used for the standard and data are given both ignoring sulfur variability and averaging

TABLE 8. PHYSICAL COAL CLEANING PROCESSES--PERCENT ENERGY AVAILABLE
FOR VARIOUS EMISSION LIMITS

Region	516 (1.2)(a)				860 (2.0)				1290 (3.0)				1720 (4.0)							
	A1	A2	A3	A4 Raw	A1	A2	A3	A4 Raw	A1	A2	A3	A4 Raw	A1	A2	A3	A4 Raw				
Variability Ignored																				
1	12	23	9	26	7	32	42	22	54	17	52	64	40	77	33	71	79	57	91	51
2	65	67	57	75	54	89	89	84	90	83	94	96	93	98	93	98	98	95	99	94
3	37	42	29	57	27	73	82	71	97	69	93	95	91	99	50	95	98	94	99	94
4	3	3	2	7	1	9	11	6	16	6	16	23	11	32	10	34	47	17	68	15
5	8	12	8	18	7	14	17	13	23	13	22	24	19	47	18	27	41	22	68	21
6	86	82	79	84	72	97	95	92	96	90	99	98	98	98	97	100	100	99	100	99
7	46	47	41	51	38	59	61	54	65	52	67	71	63	77	60	75	80	68	89	66
24-hr Average, 75 x 10 ⁶ Btu/hr																				
1	9	16	6	17	1	24	35	17	45	8	43	54	32	67	15	59	69	44	84	27
2	47	49	42	56	6	85	85	80	47	59	92	92	91	95	82	95	96	94	99	91
3	27	28	24	36	6	68	74	57	89	36	90	89	79	98	67	94	96	92	99	76
4	2	2	1	4	0	6	8	4	12	2	13	17	9	21	5	21	29	12	42	9
5	7	7	7	13	6	14	16	9	22	9	20	21	17	31	16	23	31	21	59	19
6	79	76	72	80	67	95	94	90	95	89	98	98	97	98	96	99	99	99	99	98
7	40	41	36	44	29	56	58	51	62	46	63	66	59	71	54	69	74	64	81	59
30-day Average, 75 x 10 ⁶ Btu/hr																				
1	9	16	6	17	2	26	37	18	48	9	44	56	34	69	20	62	72	48	87	31
2	47	49	42	56	23	86	86	82	88	65	93	93	91	96	87	96	97	94	99	92
3	27	28	24	36	13	71	78	65	91	44	91	90	83	93	72	94	96	93	99	86
4	2	2	1	4	1	7	10	4	13	2	14	18	9	22	7	25	35	13	50	9
5	8	10	8	15	7	14	17	11	23	11	21	23	19	36	17	24	35	21	62	20
6	83	79	75	82	70	96	94	91	95	69	99	98	97	98	96	100	99	99	100	99
7	42	42	38	45	32	57	59	52	63	47	64	67	60	72	56	71	76	65	84	61
24-hr Average, 600 MW																				
1	9	16	6	17	2	26	37	18	48	9	44	56	34	69	20	62	72	48	87	31
2	47	49	42	56	23	86	86	82	88	65	93	93	91	96	87	96	97	94	99	92
3	27	28	24	36	13	71	78	65	91	44	91	90	83	93	72	94	96	93	99	86
4	2	2	1	4	1	7	10	4	13	2	14	18	9	22	7	25	35	13	50	9
5	8	10	8	15	7	14	16	9	22	9	20	21	17	31	16	23	31	21	59	19
6	79	76	72	80	67	95	94	90	95	89	98	98	97	98	96	99	99	99	99	98
7	40	41	36	44	31	56	59	51	63	47	64	67	60	72	56	71	76	65	84	60
30-day Average, 600 MW																				
1	11	19	7	22	4	29	40	20	51	12	48	60	37	74	25	66	75	51	89	39
2	56	58	49	65	38	87	87	83	89	70	93	95	92	97	90	98	97	94	99	94
3	32	35	26	47	21	72	80	68	94	56	92	92	89	99	75	95	97	94	99	92
4	2	2	1	5	1	8	10	5	14	3	15	20	10	20	8	28	40	14	57	12
5	8	10	8	15	7	14	17	11	23	11	21	23	19	36	17	24	35	21	62	20
6	83	79	75	82	70	96	94	91	95	89	99	98	97	98	96	100	99	99	100	99
7	43	44	39	48	34	58	60	53	64	49	66	69	61	74	58	73	78	60	86	63

(a) Emission limits are given in nanograms/joule (lb/106 Btu).

(a) Emission limits are given in nanograms/joule (lb/106 Btu).

TABLE 9. CHEMICAL COAL CLEANING PROCESSES--PERCENT ENERGY AVAILABLE
FOR VARIOUS EMISSION LIMITS

Region	516 (1.2)(a)					860 (2.0)					1290 (3.0)					1720 (4.0)				
	B1	B2	B3	B4	Raw	B1	B2	B3	B4	Raw	B1	B2	B3	B4	Raw	B1	E2	B3	B4	Raw
	Variability Ignored																			
1	22	27	37	40	7	54	57	65	67	17	81	81	86	85	33	92	93	94	93	51
2	60	68	81	83	54	89	90	95	96	83	98	98	99	99	93	99	99	100	99	94
3	47	48	77	81	27	95	97	97	95	69	99	99	99	99	90	99	100	100	99	94
4	4	4	10	10	1	15	14	20	25	6	37	34	54	65	10	72	72	94	83	15
5	15	17	13	19	7	28	25	30	33	13	52	49	62	64	18	71	67	82	81	21
6	80	81	91	92	72	95	95	97	97	90	98	98	99	99	97	100	100	100	100	99
7	46	46	57	59	36	65	65	70	72	52	79	73	85	37	60	90	90	94	94	66
24-hr Average, 75 x 10 ⁶ Btu/hr																				
1	14	19	20	31	1	44	47	56	58	8	60	69	78	79	15	85	86	89	88	27
2	44	50	72	76	8	85	86	90	92	59	95	95	98	98	82	99	99	99	99	51
3	24	30	56	67	6	85	89	95	94	36	98	99	98	97	67	99	99	99	99	76
4	2	3	7	8	0	11	11	16	18	2	22	22	34	44	5	46	45	67	73	9
5	12	13	18	17	6	23	21	28	28	9	44	39	53	56	16	64	56	71	76	19
6	74	76	84	88	67	93	94	96	97	89	98	98	98	99	96	99	99	100	100	98
7	39	42	51	54	29	61	62	66	67	46	72	72	79	80	54	83	82	89	90	59
30-day Average, 75 x 10 ⁶ Btu/hr																				
1	14	19	20	31	2	48	51	59	61	9	71	71	81	81	20	88	88	91	90	31
2	44	50	72	76	23	86	88	91	94	65	96	97	98	98	87	99	99	99	99	92
3	24	30	56	67	13	93	90	96	34	44	98	99	98	98	72	99	99	99	99	86
4	2	3	7	8	1	12	12	18	20	2	24	23	39	48	7	54	52	74	76	9
5	13	15	18	18	7	26	23	29	30	11	49	41	57	60	17	69	61	77	78	20
6	77	79	87	90	70	94	94	97	97	89	98	98	99	99	96	100	99	100	100	99
7	41	43	52	55	32	62	63	68	69	47	73	73	82	82	56	85	85	91	91	61
24-hr Average, 600 MW																				
1	14	19	28	31	2	48	51	59	61	9	71	71	81	81	20	88	88	91	90	31
2	44	50	72	76	23	86	88	91	94	65	96	97	98	98	87	99	99	99	99	92
3	24	30	56	67	13	93	90	96	94	44	98	99	98	98	72	99	99	99	99	86
4	2	3	7	8	1	12	12	18	20	2	24	23	39	48	7	54	52	74	76	9
5	12	13	18	17	6	23	21	28	28	9	44	39	53	56	16	64	56	71	76	19
6	74	76	84	88	67	93	94	96	97	89	98	98	99	99	96	99	99	100	100	98
7	39	42	51	54	31	62	63	67	69	47	73	73	79	82	56	85	84	91	91	60
30-day Average, 600 MW																				
1	14	19	28	31	4	51	54	62	64	12	75	76	84	83	25	90	90	92	92	39
2	52	59	77	80	38	83	89	93	95	78	97	97	98	98	90	99	99	99	99	96
3	35	39	56	74	21	94	94	97	95	56	99	99	99	98	75	99	99	100	100	92
4	3	3	9	9	1	14	13	19	22	3	28	28	46	58	8	62	60	79	79	12
5	13	15	18	18	7	26	23	29	30	11	49	41	57	60	17	69	61	77	78	20
6	77	79	87	90	70	94	94	97	97	89	98	98	99	99	96	100	99	100	100	99
7	43	45	54	56	34	63	64	69	70	49	75	75	82	85	58	88	87	92	92	63

(a) Emission limits are given in nanograms/joule (lb/10⁶ Btu).

TABLE 10. PHYSICAL COAL CLEANING PROCESSES--EMISSION STANDARDS
THAT CAN BE MET FOR 50 PERCENT AND 25 PERCENT ENERGY
AVAILABILITIES

(nanograms/joule)										
Region	50 percent					25 percent				
	A1	A2	A3	A4	Raw	A1	A2	A3	A4	Raw
Variability Ignored										
1	1247	989	1547	816	1720	773	558	902	516	1075
2	473	430	473	430	516	344	344	344	300	386
3	645	601	688	516	638	430	430	430	386	516
4	1977	1805	2494	1547	2735	1547	1376	1977	1161	2192
5	2450	1892	3010	1332	3354	1633	1376	1935	902	2020
6	258	258	344	258	386	172	172	215	172	300
7	601	558	731	516	816	300	300	344	258	386
24-hr Average, 75×10^6 Btu/hr										
1	1496	1186	1857	980	2683	929	670	1083	619	1676
2	567	515	567	515	804	412	412	464	361	603
3	773	722	825	619	1073	515	515	515	464	604
4	2373	2167	2992	1857	4360	1857	1651	2373	1393	3421
5	2794	2156	3431	1519	3823	1862	1568	2205	1029	2303
6	294	294	392	294	441	196	196	245	196	343
7	731	688	816	645	1075	344	344	386	300	516
30-day Average, 75×10^6 Btu/hr										
1	1421	1127	1764	931	2373	832	637	1029	588	1483
2	539	490	539	490	712	392	392	441	343	534
3	735	686	764	588	949	490	490	490	441	712
4	2254	2058	2843	1764	3857	1764	1568	2254	1323	3026
5	2647	2043	3250	1439	3622	1764	1486	2089	975	2182
6	278	278	371	278	417	185	185	232	185	325
7	688	688	816	601	938	300	300	386	258	430
30-day Average, 600 MW										
1	1346	1068	1671	882	2029	835	603	975	557	1268
2	510	464	510	464	608	371	371	417	315	456
3	696	650	743	557	811	464	464	464	417	608
4	2136	1950	2693	1671	3298	1671	1486	2136	1253	2587
5	2647	2043	3250	1439	3622	1764	1486	2089	975	2182
6	278	278	371	278	417	185	185	232	185	325
7	731	688	816	645	988	344	344	386	300	473
24-hr Average, 600 MW										
1	1421	1127	1764	931	2373	832	637	1029	588	1483
2	539	490	539	490	712	392	392	441	343	534
3	735	686	764	588	949	490	490	490	441	712
4	2254	2058	2843	1764	3857	1764	1568	2254	1323	3026
5	2794	2156	3431	1519	3823	1862	1568	2205	1029	2303
6	294	294	392	294	441	196	196	245	196	343
7	688	645	773	558	902	300	300	386	258	430

TABLE 10. (Continued)

(lb SO₂/10⁶ Btu)

Region	50 percent					25 percent				
	A1	A2	A3	A4	Raw	A1	A2	A3	A4	Raw
Variability Ignored										
1	2.9	2.3	3.6	1.9	4.0	1.9	1.3	2.1	1.2	2.5
2	1.1	1.0	1.1	1.0	1.2	.3	.6	.9	.7	.9
3	1.5	1.4	1.6	1.2	1.6	1.0	1.0	1.0	.9	1.2
4	4.6	4.2	5.8	3.6	5.5	3.6	3.2	4.6	2.7	5.1
5	5.7	4.4	7.0	3.1	7.5	3.8	3.2	4.5	2.1	4.7
6	.6	.6	.8	.6	.9	.4	.4	.5	.4	.7
7	1.4	1.3	1.7	1.2	1.9	.7	.7	.8	.6	.9
24-hr Average, 75 x 10 ⁶ Btu/hr										
1	3.5	2.8	4.3	2.3	6.2	2.2	1.6	2.5	1.4	3.9
2	1.3	1.2	1.3	1.2	1.9	1.0	1.0	1.1	.8	1.4
3	1.8	1.7	1.9	1.4	2.5	1.2	1.2	1.2	1.1	1.9
4	5.5	5.0	7.0	4.3	10.1	4.3	3.8	5.5	3.2	8.0
5	6.5	5.0	8.0	3.5	8.9	4.3	3.6	5.1	2.4	5.4
6	.7	.7	.9	.7	1.0	.5	.5	.6	.5	.8
7	1.7	1.6	1.9	1.5	2.5	.5	.8	.9	.7	1.2
30-day Average, 75 x 10 ⁶ Btu/hr										
1	3.3	2.6	4.1	2.2	5.5	2.1	1.5	2.4	1.4	3.5
2	1.3	1.1	1.3	1.1	1.7	.9	.9	1.0	.8	1.2
3	1.7	1.6	1.8	1.4	2.2	1.1	1.1	1.1	1.0	1.7
4	5.2	4.8	6.6	4.1	9.0	4.1	3.6	5.2	3.1	7.0
5	6.2	4.8	7.6	3.3	8.4	4.1	3.5	4.9	2.3	5.1
6	.6	.6	.9	.6	1.0	.4	.4	.5	.4	.8
7	1.6	1.6	1.9	1.4	2.3	.7	.7	.9	.6	1.0
30-day Average, 600 MW										
1	3.1	2.5	3.9	2.1	4.7	1.9	1.4	2.3	1.3	3.0
2	1.2	1.1	1.2	1.1	1.4	.9	.9	1.0	.8	1.1
3	1.6	1.5	1.7	1.3	1.9	1.1	1.1	1.1	1.0	1.4
4	5.0	4.5	6.3	3.9	7.7	3.9	3.5	5.0	2.9	6.0
5	6.2	4.8	7.6	3.3	8.4	4.1	3.5	4.9	2.3	5.1
6	.6	.6	.9	.6	1.0	.4	.4	.5	.4	.8
7	1.7	1.6	1.9	1.5	2.3	.8	.8	.9	.7	1.1
24-hr Average, 600 MW										
1	3.3	2.6	4.1	2.2	5.5	2.1	1.5	2.4	1.4	3.5
2	1.3	1.1	1.3	1.1	1.7	.9	.9	1.0	.8	1.2
3	1.7	1.6	1.8	1.4	2.2	1.1	1.1	1.1	1.0	1.7
4	5.2	4.8	6.6	4.1	9.0	4.1	3.6	5.2	3.1	7.0
5	6.5	5.0	8.0	3.5	8.9	4.3	3.6	5.1	2.4	5.4
6	.7	.7	.9	.7	1.0	.5	.5	.6	.5	.8
7	1.6	1.5	1.8	1.3	2.1	.7	.7	.9	.6	1.0

TABLE 11. CHEMICAL COAL CLEANING PROCESSES--EMISSION STANDARDS
THAT CAN BE MET FOR 50 PERCENT AND 25 PERCENT
ENERGY AVAILABILITIES

(nanograms/joule)

Region	50 percent					25 percent				
	B1	B2	B3	B4	Raw	B1	B2	B3	B4	Raw
<u>Variability Ignored</u>										
1	816	773	688	645	1720	558	516	430	386	1075
2	473	430	386	386	516	386	344	258	258	336
3	558	558	430	386	688	430	430	344	300	516
4	1462	1462	1247	1161	2795	1161	1161	946	860	2192
5	1247	1332	1075	1032	3354	816	860	731	688	2020
6	344	300	215	215	386	258	258	129	129	300
7	558	558	430	386	816	344	300	215	215	386
<u>24-hr Average, 75 x 10⁶ Btu/hr</u>										
1	980	928	825	773	2683	670	619	515	464	1676
2	567	515	464	464	804	464	412	309	309	603
3	670	670	515	464	1073	515	515	412	361	804
4	1754	1754	1496	1393	4360	1393	1393	1135	1031	3421
5	1421	1519	1225	1176	3823	931	980	833	784	2303
6	392	343	245	245	441	294	294	147	147	343
7	688	645	516	473	1075	386	386	258	258	430
<u>30-day Average, 75 x 10⁶ Btu/hr</u>										
1	931	882	784	735	2373	637	588	490	441	1483
2	539	490	441	441	712	441	392	294	294	534
3	637	637	490	441	949	490	490	392	343	712
4	1666	1666	1421	1323	3857	1323	1323	1078	980	3026
5	1346	1439	1160	1114	3622	882	928	789	743	2182
6	371	325	232	232	417	278	278	139	139	325
7	645	645	516	430	988	386	344	258	215	430
<u>30-day Average, 600 MW</u>										
1	882	835	743	696	2029	603	557	464	417	1268
2	510	464	417	417	608	417	371	278	278	456
3	603	603	464	417	811	464	464	371	325	608
4	1578	1578	1346	1253	3293	1253	1253	1021	928	2587
5	1346	1439	1160	1114	3622	882	928	789	743	2182
6	371	325	232	232	417	278	278	139	139	325
7	688	645	516	430	988	386	386	258	215	430
<u>24-hr Average, 600 MW</u>										
1	931	882	784	735	2373	637	588	490	441	1483
2	539	490	441	441	712	441	392	294	294	534
3	637	637	490	441	949	490	490	392	343	712
4	1666	1666	1421	1323	3857	1323	1323	1078	980	3026
5	1421	1519	1225	1176	3823	931	980	833	784	2303
6	392	343	245	245	441	294	294	147	147	343
7	645	601	516	430	902	386	344	258	215	430

TABLE 11. (Continued)

(lb/10⁶ Btu)

Region	50 percent					25 percent				
	B1	B2	B3	B4	Raw	B1	B2	B3	B4	Raw
<u>No Variability</u>										
1	1.9	1.8	1.6	1.5	4.0	1.3	1.2	1.0	.9	2.5
2	1.1	1.0	.9	.9	1.2	.9	.8	.6	.6	.9
3	1.3	1.3	1.0	.9	1.6	1.0	1.0	.8	.7	1.2
4	3.4	3.4	2.9	2.7	6.5	2.7	2.7	2.2	2.0	5.1
5	2.9	3.1	2.5	2.4	7.8	1.9	2.0	1.7	1.6	4.7
6	.8	.7	.5	.5	.9	.6	.6	.3	.3	.7
7	1.3	1.3	1.0	.9	1.9	.8	.7	.5	.5	.9
<u>24-hr Variability, 75 x 10⁶ Btu/hr</u>										
1	2.3	2.2	1.9	1.8	6.2	1.6	1.4	1.2	1.1	3.9
2	1.3	1.2	1.1	1.1	1.9	1.1	1.0	.7	.7	1.4
3	1.6	1.6	1.2	1.1	2.5	1.2	1.2	1.0	.8	1.9
4	4.1	4.1	3.5	3.2	10.1	3.2	3.2	2.6	2.4	8.0
5	3.3	3.5	2.9	2.7	8.9	2.2	2.3	1.9	1.8	5.4
6	.9	.8	.6	.6	1.0	.7	.7	.3	.3	.8
7	1.6	1.5	1.2	1.1	2.5	.9	.9	.6	.6	1.0
<u>30-day Variability, 75 x 10⁶ Btu/hr</u>										
1	2.2	2.1	1.8	1.7	5.5	1.5	1.4	1.1	1.0	3.5
2	1.3	1.1	1.0	1.0	1.7	1.0	.9	.7	.7	1.2
3	1.5	1.5	1.1	1.0	2.2	1.1	1.1	.9	.8	1.7
4	3.9	3.9	3.3	3.1	9.0	3.1	3.1	2.5	2.3	7.0
5	3.1	3.3	2.7	2.6	8.4	2.1	2.2	1.8	1.7	5.1
6	.9	.8	.5	.5	1.0	.6	.6	.3	.3	.8
7	1.5	1.5	1.2	1.0	2.3	.9	.8	.6	.5	1.0
<u>30-day Variability, 600 MW</u>										
1	2.1	1.9	1.7	1.6	4.7	1.4	1.3	1.1	1.0	3.0
2	1.2	1.1	1.0	1.0	1.4	1.0	.9	.6	.6	1.1
3	1.4	1.4	1.1	1.0	1.9	1.1	1.1	.9	.8	1.4
4	3.7	3.7	3.1	2.9	7.7	2.9	2.9	2.4	2.2	6.0
5	3.1	3.3	2.7	2.6	8.4	2.1	2.2	1.8	1.7	5.1
6	.9	.8	.5	.5	1.0	.6	.6	.3	.3	.8
7	1.6	1.5	1.2	1.0	2.3	.9	.9	.6	.5	1.0
<u>24-hr Variability, 600 MW</u>										
1	2.2	2.1	1.8	1.7	5.5	1.5	1.4	1.1	1.0	3.5
2	1.3	1.1	1.0	1.0	1.7	1.0	.9	.7	.7	1.2
3	1.5	1.5	1.1	1.0	2.2	1.1	1.1	.9	.8	1.7
4	3.9	3.9	3.3	3.1	9.0	3.1	3.1	2.5	2.3	7.0
5	3.3	3.5	2.9	2.7	8.9	2.2	2.3	1.9	1.8	5.4
6	.9	.8	.6	.6	1.0	.7	.7	.3	.3	.8
7	1.5	1.4	1.2	1.0	2.1	.9	.8	.6	.5	1.0

sulfur variability over 24 hours and 30 days for a 75×10^6 Btu/hour boiler and a 600 MW boiler.

Figures 2-13 show the availability of the reserve base for Northern Appalachian, Eastern Midwest, and Western regions to meet standards which require removal of a percentage of the sulfur in the raw coal in addition to an upper level of emissions of $2.0 \text{ lb SO}_2/10^6 \text{ Btu}$. A floor of $0.2 \text{ lb SO}_2/10^6 \text{ Btu}$ was assumed; if the raw coal emission level is below this floor, then the sulfur removal requirement is lifted and cleaning is assumed to be unnecessary. In Figures 2-7 the sulfur variability is ignored while in Figures 8-13 a 24-hour averaging period for a 75×10^6 Btu/hr boiler is assumed.

Although cleaning of raw coal prior to combustion significantly increases the coal available to meet given emission standards, the combination of cleaning prior to combustion and flue gas desulfurization of the emissions will even further enhance the coal availability. The combined effects of physical coal cleaning and flue gas desulfurization on coal availability are shown in Table 12. For the four physical cleaning processes, A1-A4, and for each region, the percent energy available to meet sulfur removal standards of 90 percent, 85 percent, and 75 percent is shown as a function of the FGD removal efficiency. A floor of $0.2 \text{ lb SO}_2/10^6 \text{ Btu}$ was used for the raw coal; below this level FGD and PCC cleaning were assumed to be unnecessary. A ceiling of $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$ was assumed; if the emission level of the coal after PCC and FGD processing would be greater than this ceiling, then FGD at the percent sulfur removal standard was assumed to be necessary, regardless of the sulfur removal by PCC. Example plots of these curves for Northern Appalachia, Eastern Midwest, and Western regions and for physical separation at 1.6 s.g. and 1-1/2-inch top size, are shown in Figures 14-16.

RPAM Methodology

A generalized approach was taken to the evaluation of the desulfurization potential of coals. The methodology, termed RPAM (Reserve Processing Assessment Model), characterizes the entire U.S. reserve base via 36,000 composite coal analyses showing total weight, percent ash, percent sulfur, and Btu content. In addition, each reserve base record is associated with one float-sink analysis as reported by Cavallaro, Johnston, and Deurbrouck in RI 8118. (3-2)

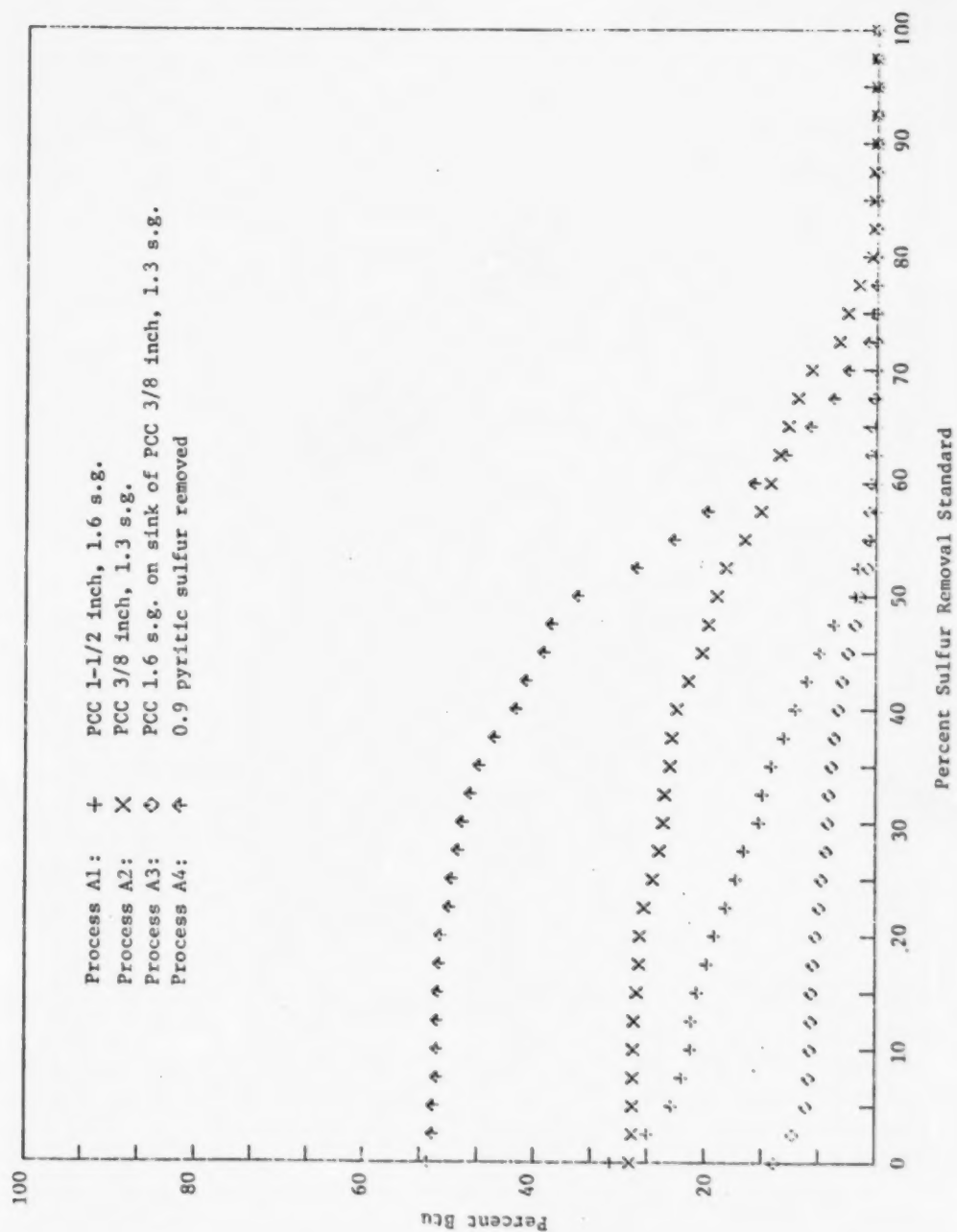


FIGURE 2. NORTHERN APPALACHIAN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES A1-A4)

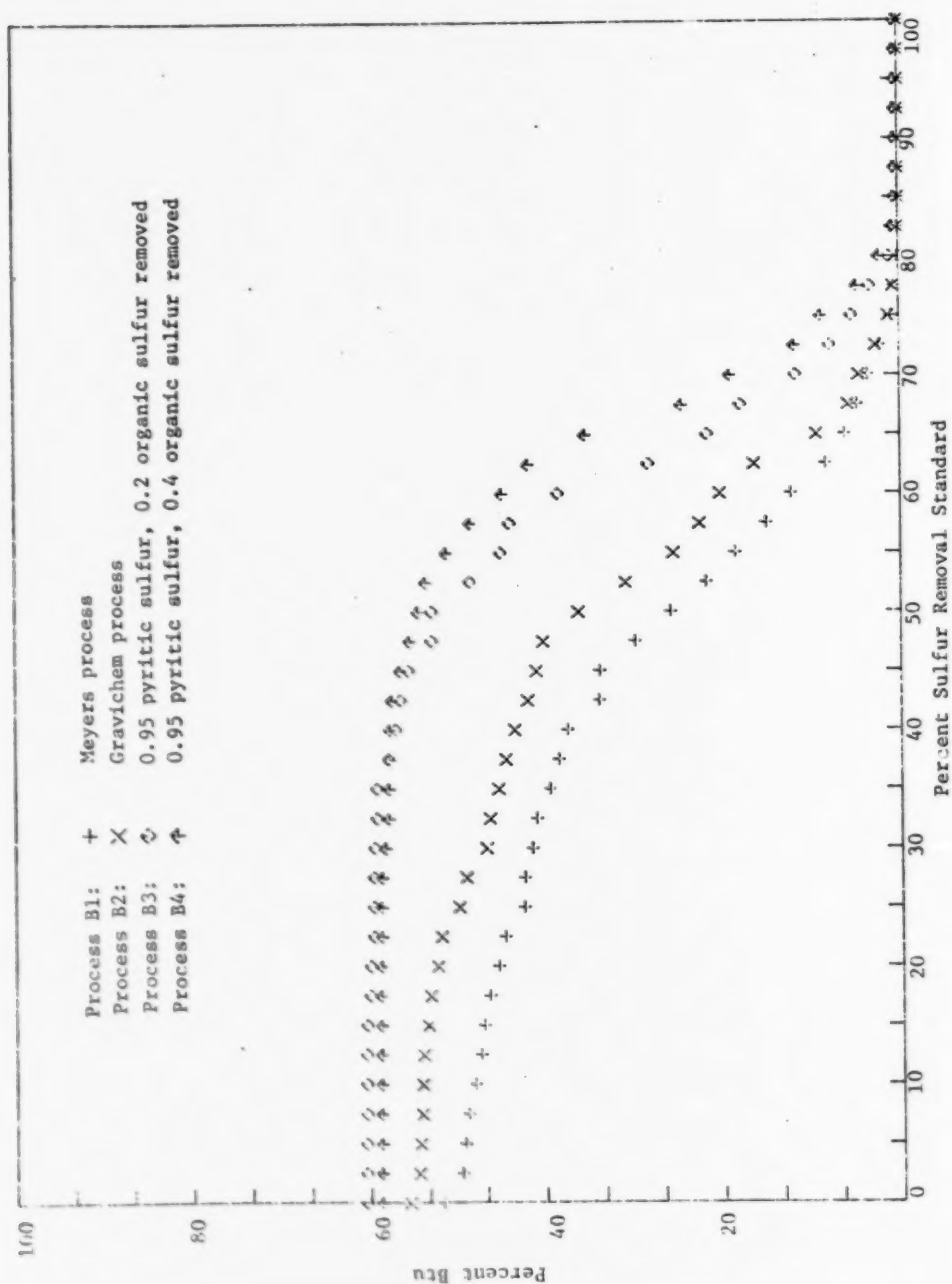


FIGURE 3. NORTHERN APPALACHIAN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES B1-B4)

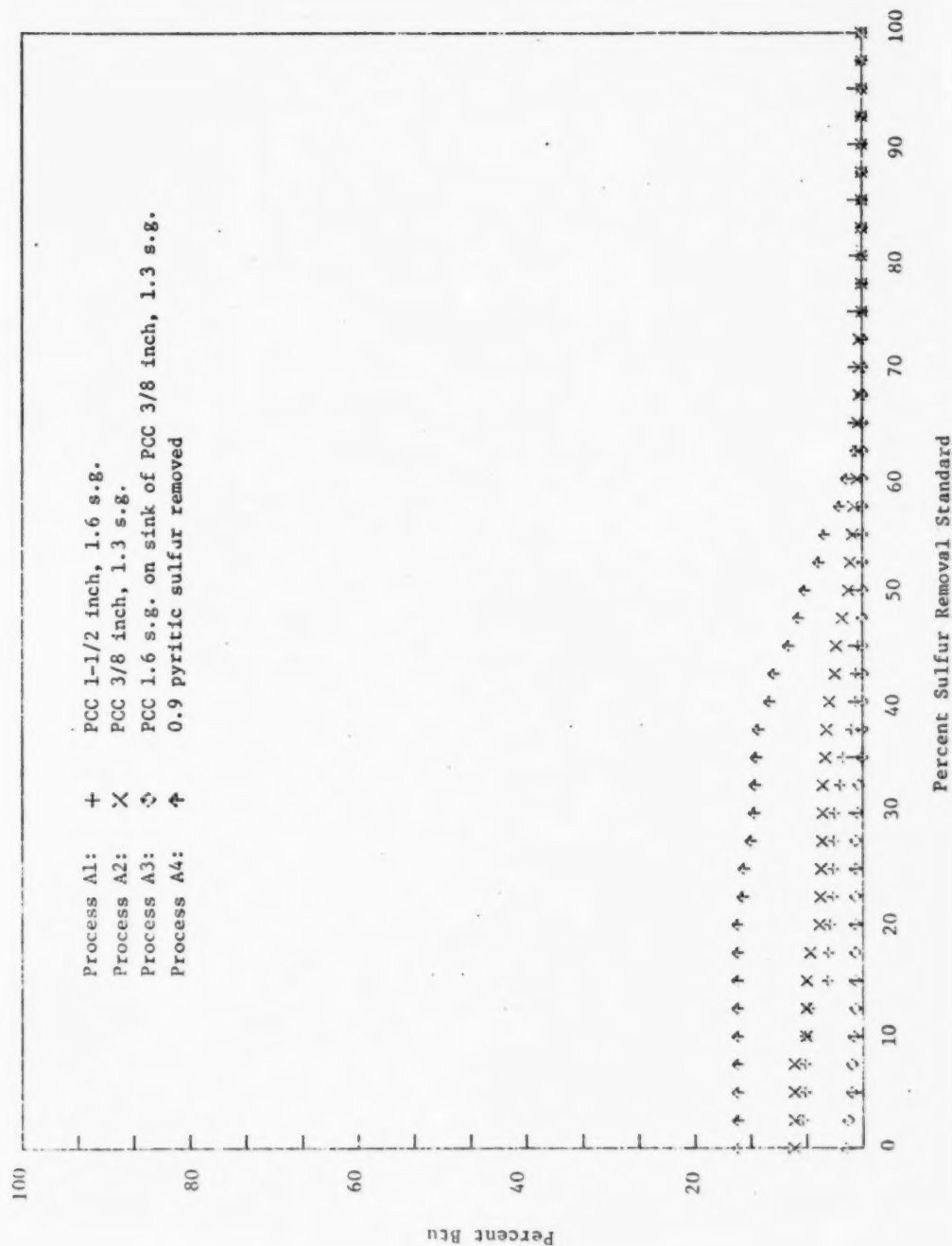


FIGURE 4. EASTERN MIDWEST REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES A1-A4)

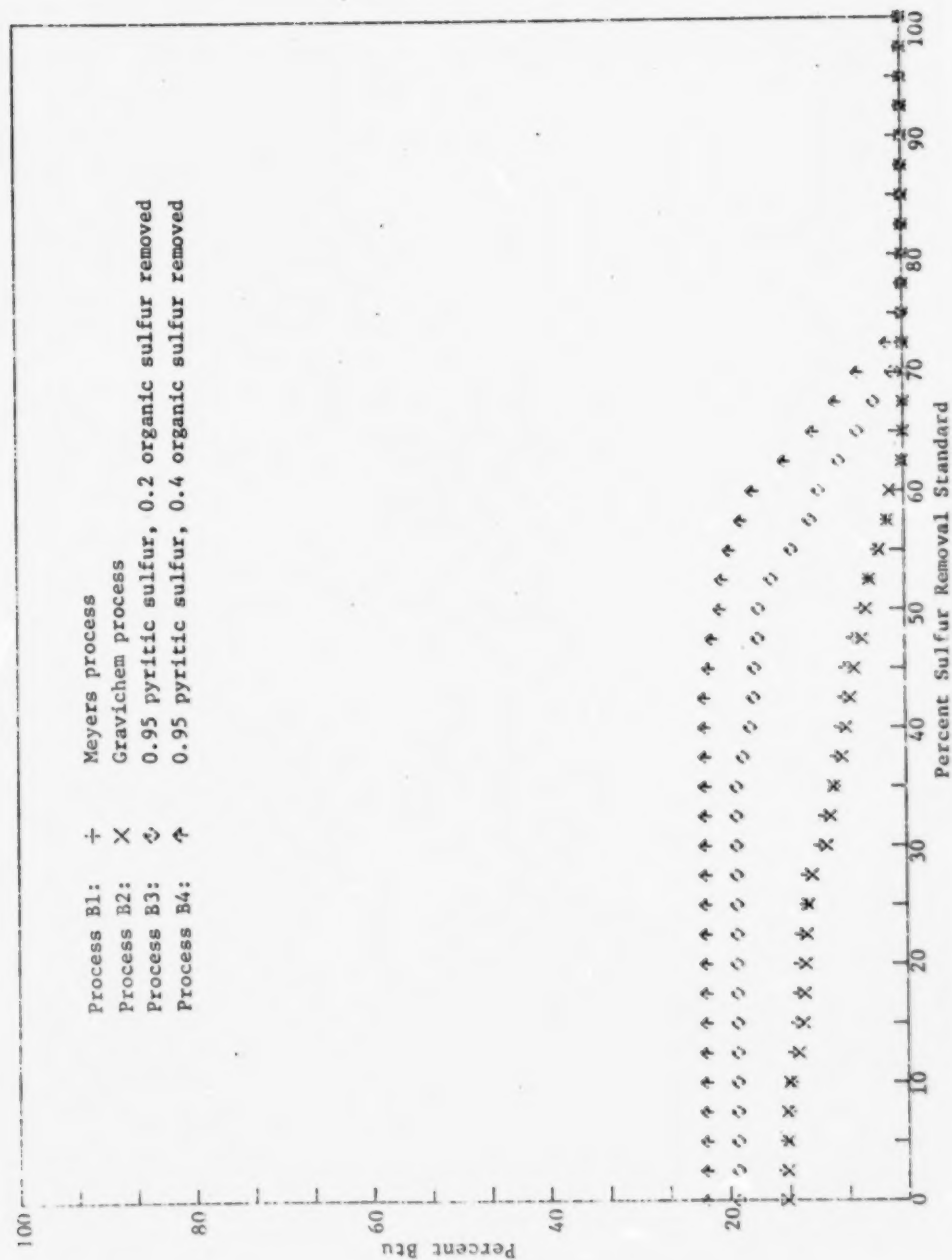


FIGURE 5. EASTERN MIDWEST REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES B1-B4)

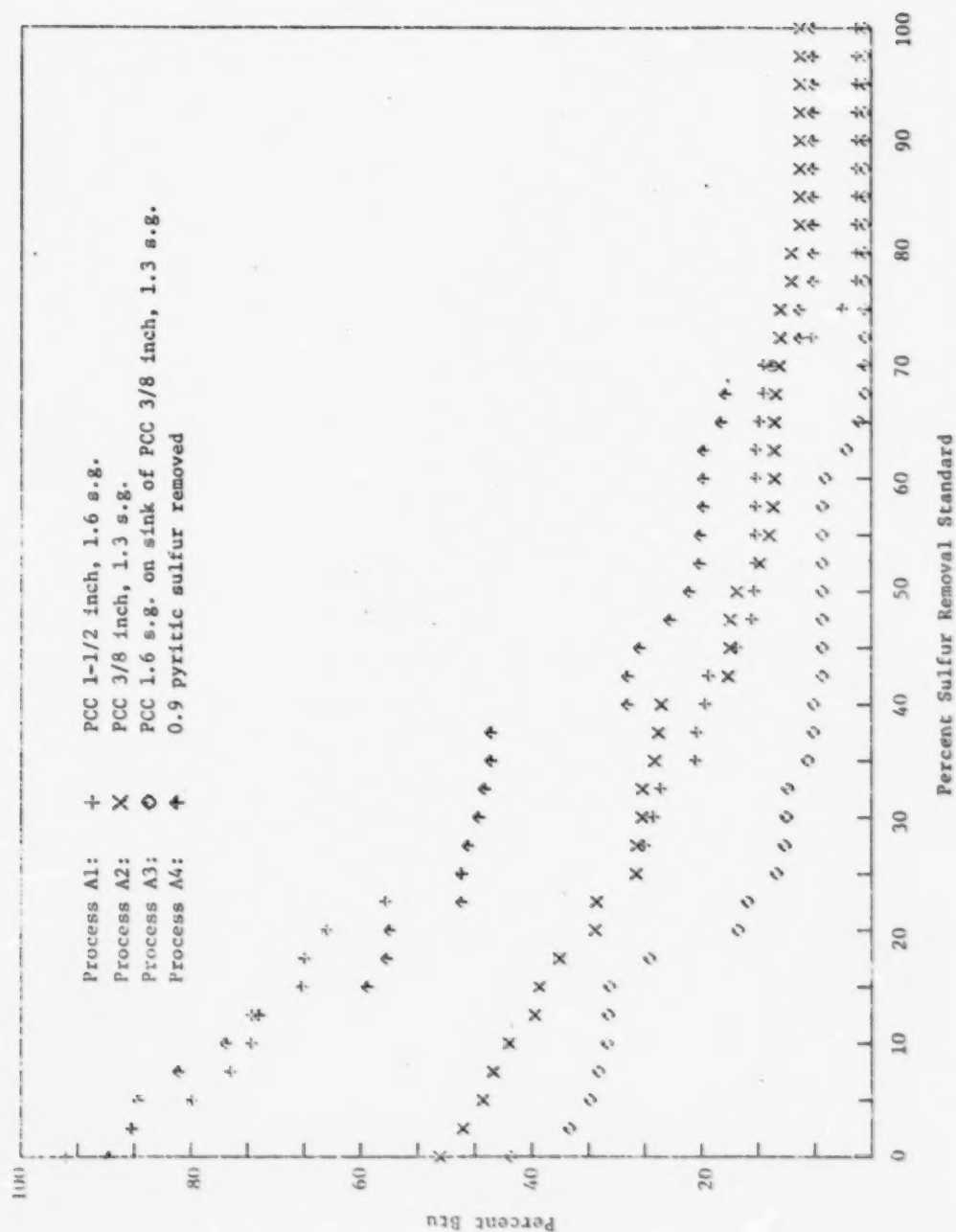


FIGURE 6. WESTERN REGION; ENERGY AVAILABILITY TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES A1-A4)

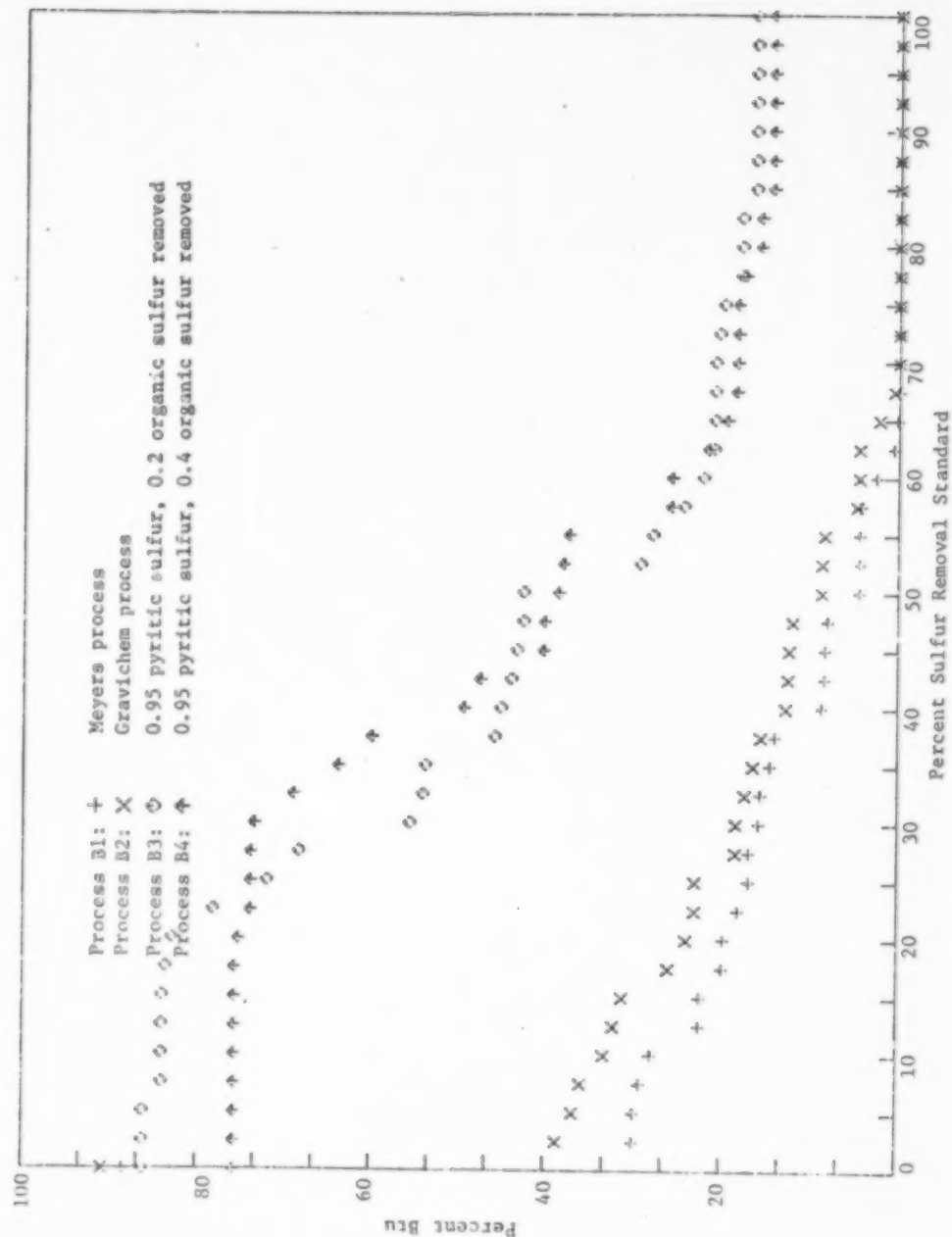


FIGURE 7. WESTERN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT, SULFUR VARIABILITY IGNORED (PROCESSES B1-B4)

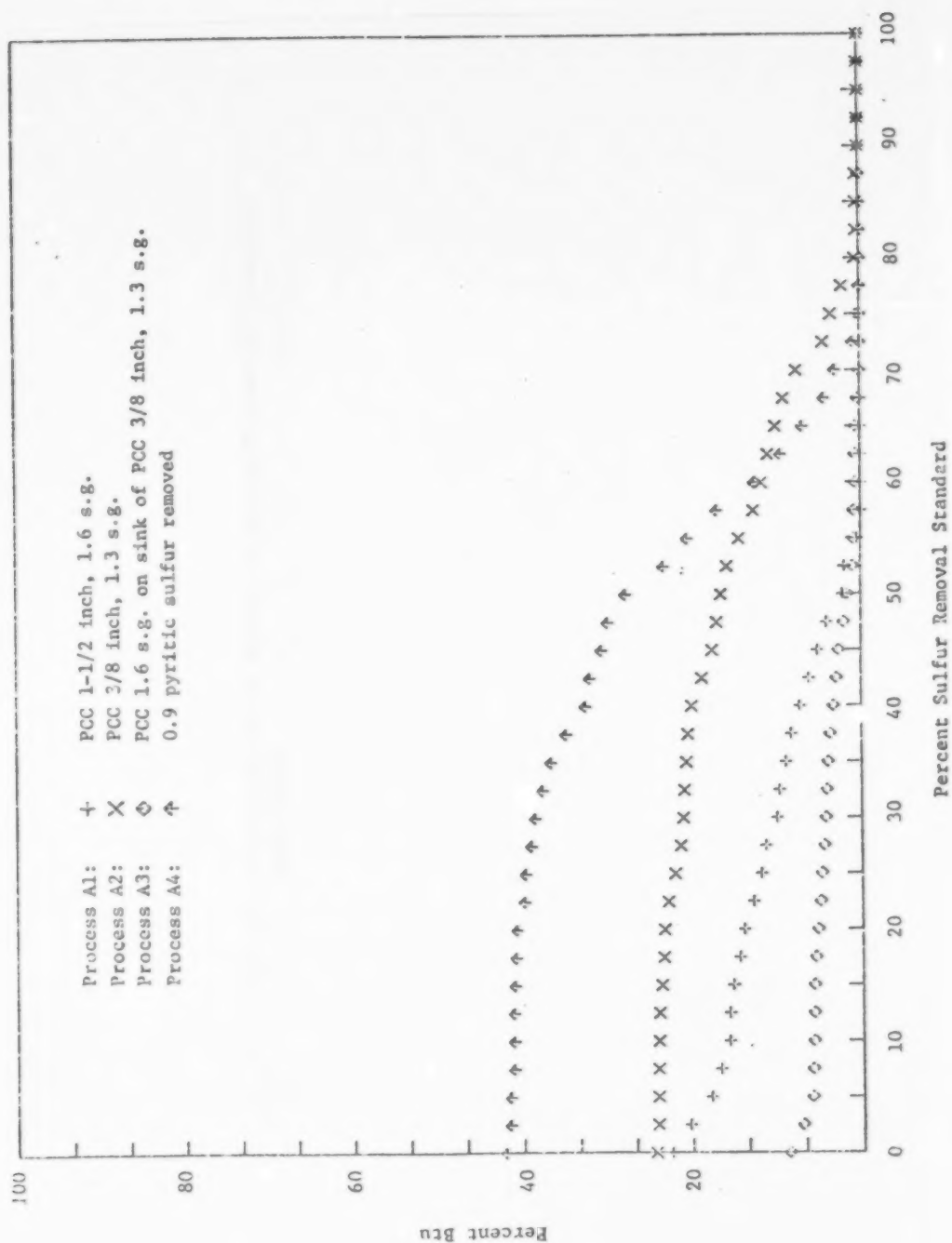


FIGURE 8. NORTHERN APALACHIAN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A 75 x 10⁶ BTU/HR BOILER (PROCESSES A1-A4)

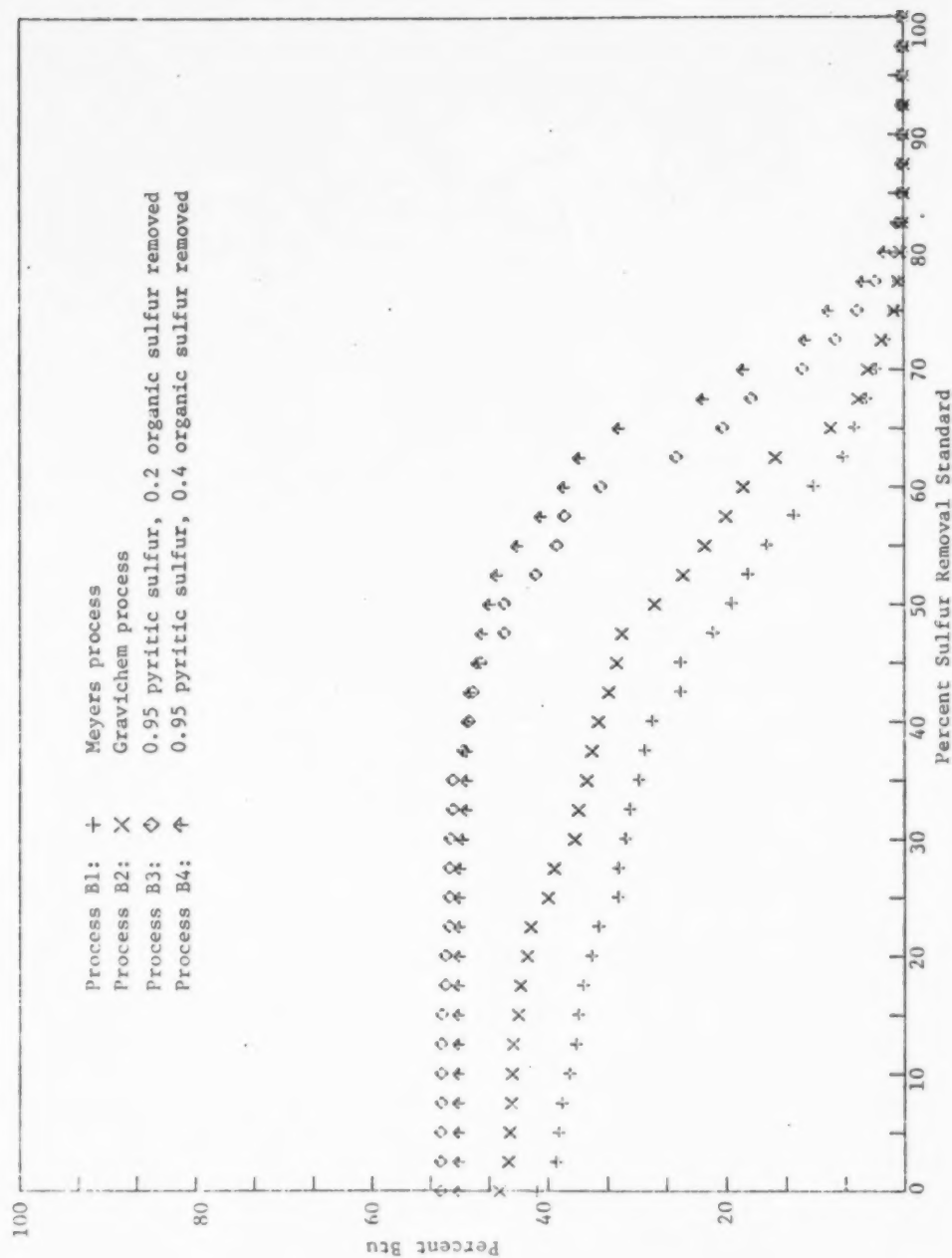


FIGURE 9. NORTHERN APPALACHIAN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A $2.0 \text{ LB SO}_2/10^6 \text{ BTU}$ EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A $75 \times 10^6 \text{ BTU/HR}$ BOILER (PROCESSES B1-B4)

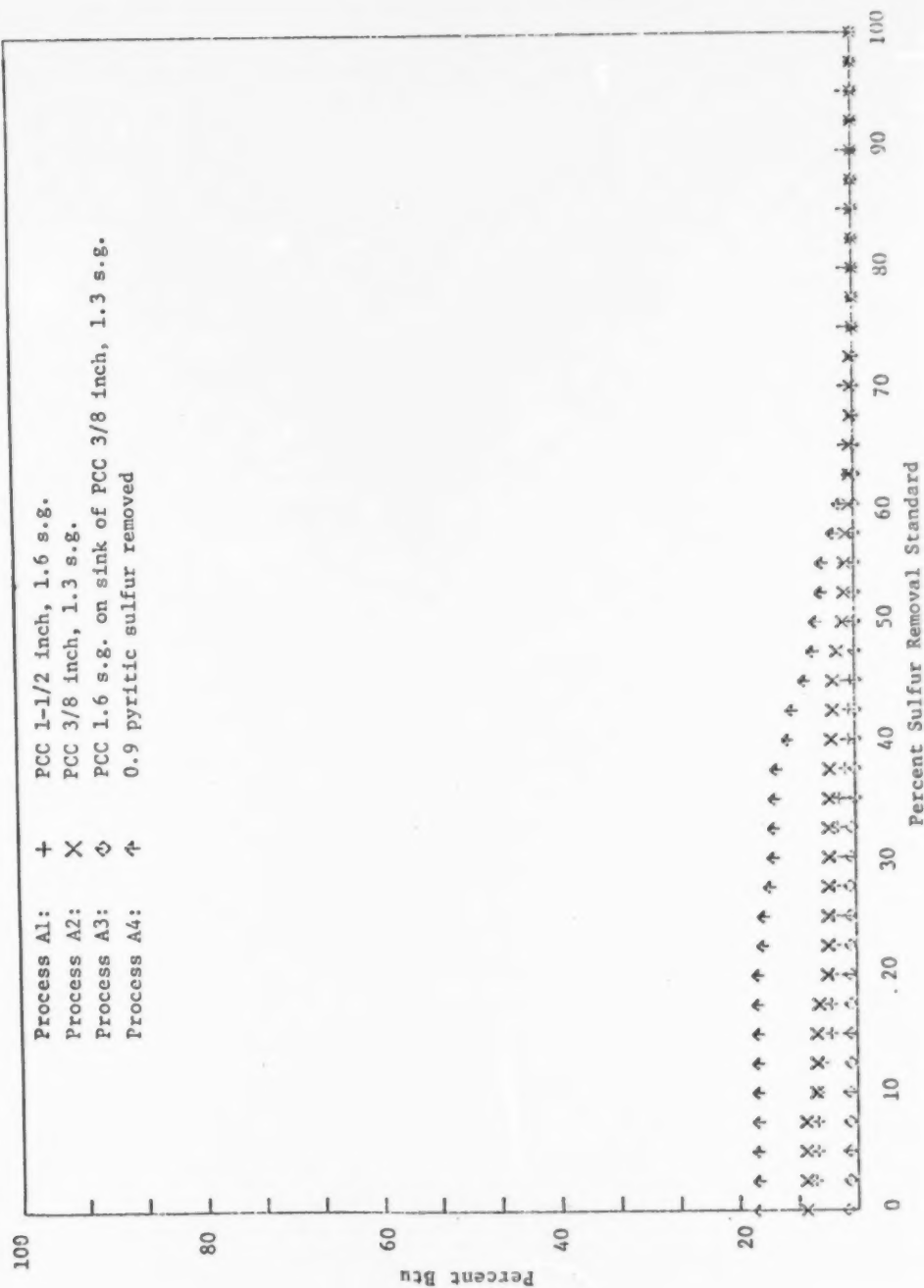


FIGURE 10. EASTERN MIDWEST REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A 75 x 10⁶ BTU/HR BOILER (PROCESSES A1-A4)

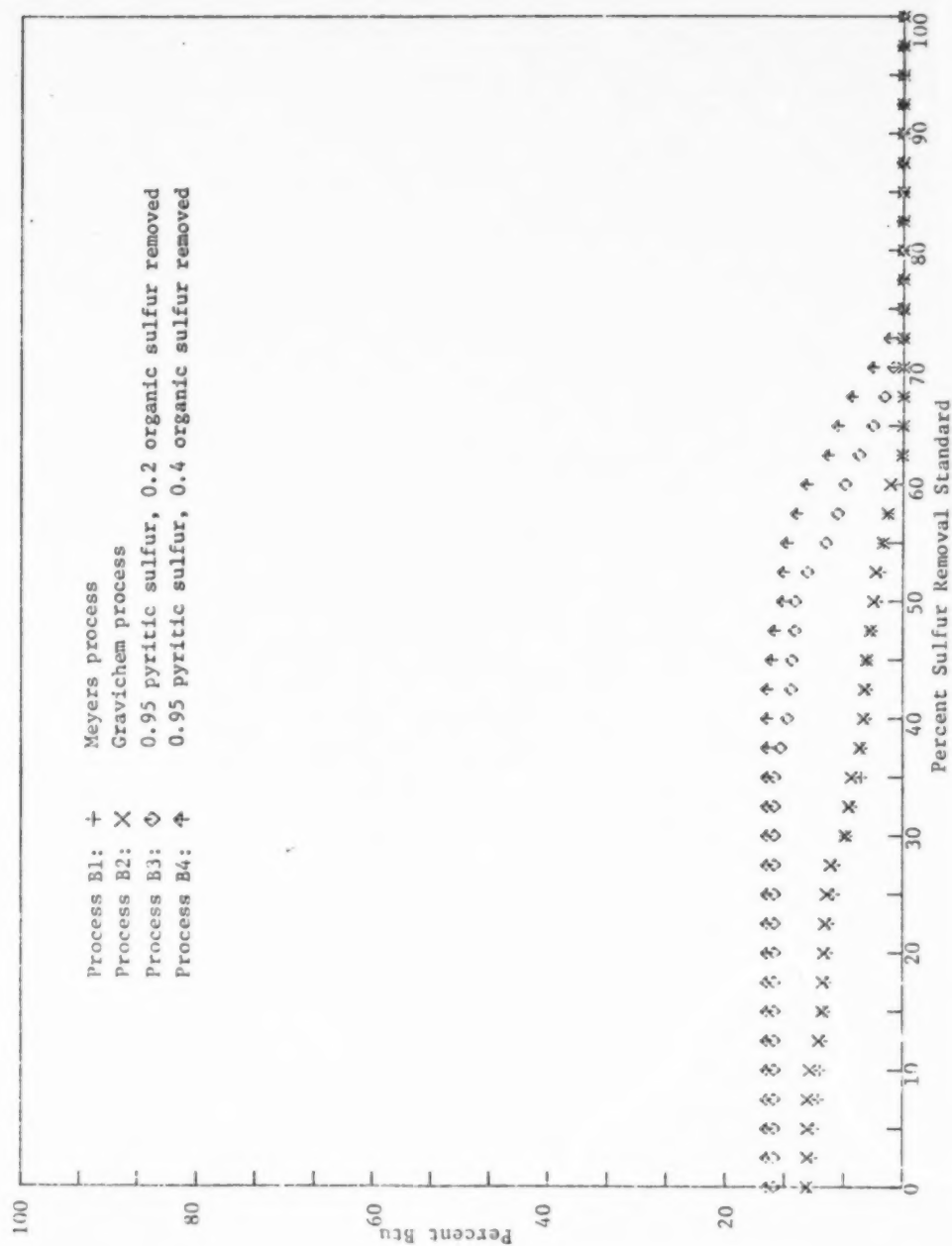


FIGURE 11. EASTERN MIDWEST REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A 2.0 LB SO₂/10⁶ BTU EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A 75 x 10⁶ BTU/HR BOILER (PROCESSES B1-B4)

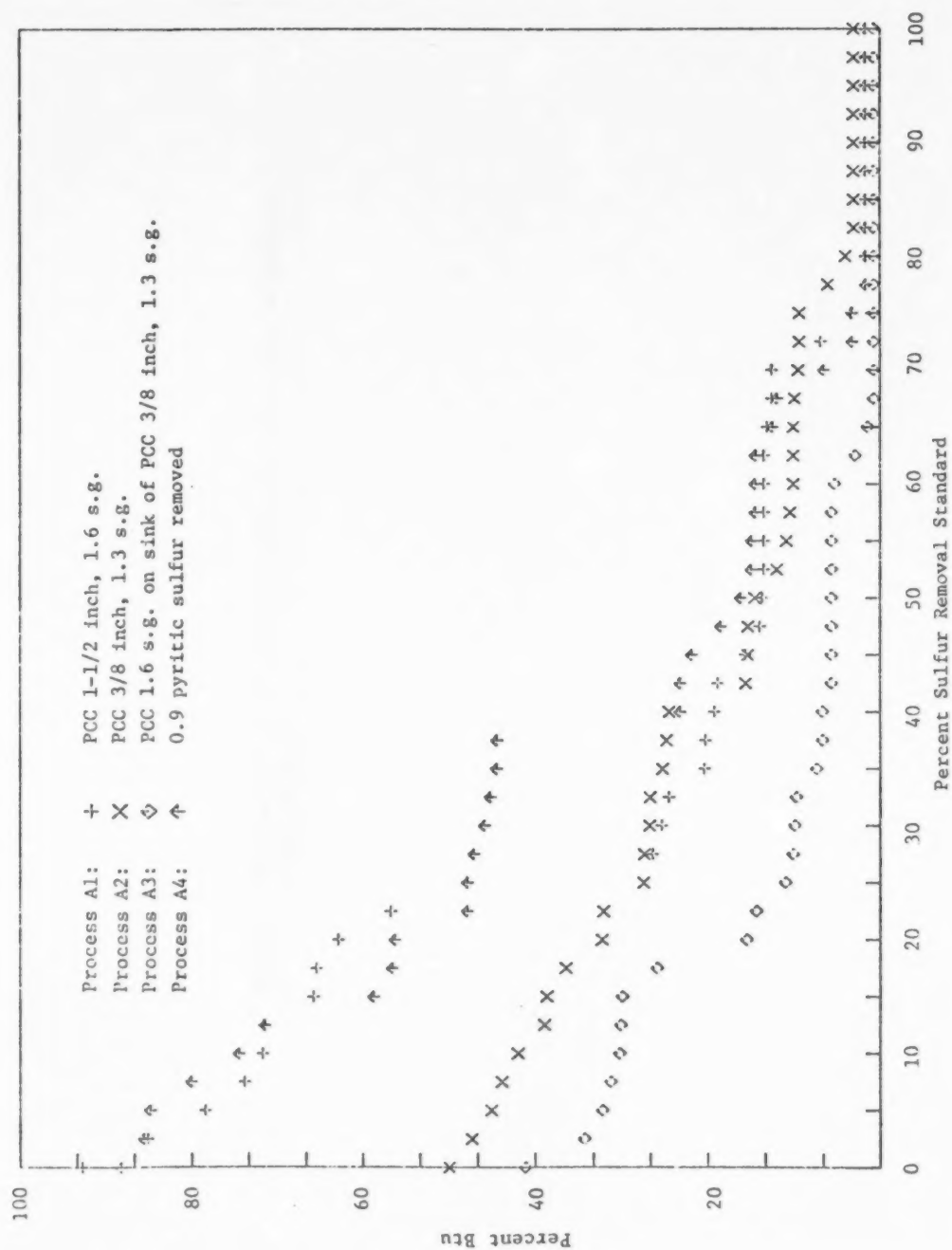


FIGURE 12. WESTERN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A $2.0 \text{ LB SO}_2/10^6 \text{ BTU}$ EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A $75 \times 10^6 \text{ BTU/HR}$ BOILER (PORCESSES A1-A4)

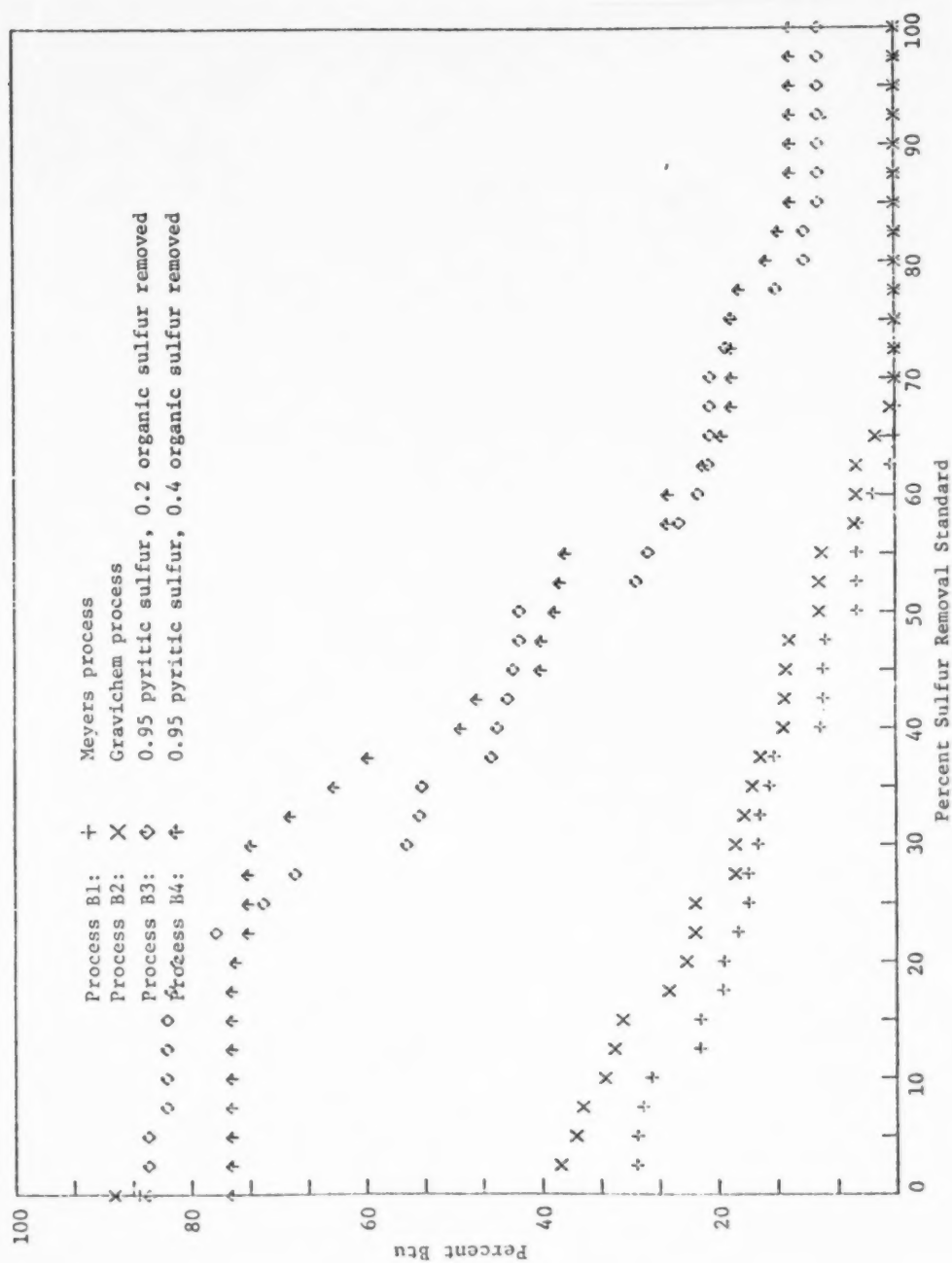


FIGURE 13. WESTERN REGION; ENERGY AVAILABLE TO MEET PERCENT SULFUR REMOVAL STANDARDS WITH A $2.0 \text{ LB SO}_2/10^6 \text{ BTU}$ EMISSION LIMIT WITH 24-HOUR AVERAGING FOR A $75 \times 10^6 \text{ BTU/HR}$ BOILER (PROCESSES B1-B4)

TABLE 12. PCC + FGD PROCESSES; ENERGY AVAILABLE TO MEET VARIOUS SO₂ REDUCTION STANDARDS
(CEILING 1.2, FLOOR 0.2 LB SO₂/10⁶ BTU) VERSUS PERCENT FGD REMOVAL EFFICIENCY

FGD Efficiency	PCC 1-1/2 inch, 1.6 s.g. (Reduction Standard, %)			PCC 3/8 inch, 1.3 s.g. (Reduction Standard, %)			PCC 1.6 s.g. on sink of 3/8 inch, 1.3 s.g. (Reduction Standard, %)			0.9 pyritic sulfur removed (Reduction Standard, %)		
	90	85	75	90	85	75	90	85	75	90	85	75
Northern Appalachia												
50	0	0	0	1	9	25	0	0	4	0	5	58
55	0	0	15	2	11	33	0	1	6	0	9	72
60	0	0	25	4	14	39	0	1	9	1	17	80
65	0	2	37	8	20	46	0	1	15	4	32	89
70	0	11	71	12	28	48	1	4	23	11	61	90
75	0	24	95	18	39	49	1	9	40	26	80	93
80	13	63	55	31	48	49	6	21	47	68	90	93
85	45	55	55	47	49	49	17	43	47	90	93	93
90	95	55	55	49	49	49	44	47	47	93	93	93
Southern Appalachia												
50	0	0	1	0	0	2	0	0	0	0	0	8
55	0	0	3	0	0	4	0	0	0	0	2	14
60	0	0	4	0	0	10	0	0	1	0	4	23
65	0	0	19	0	0	21	0	0	5	0	5	44
70	0	2	33	0	2	34	0	0	14	2	11	64
75	0	4	55	0	9	62	0	0	28	4	23	79
80	2	29	96	2	31	64	0	13	32	12	56	93
85	21	96	96	26	64	64	7	29	33	51	93	93
90	96	96	96	64	64	64	31	33	33	93	93	93
Alabama												
50	0	0	0	0	3	3	0	0	0	0	0	19
55	0	0	0	0	3	6	0	0	0	0	0	30
60	0	0	0	0	3	10	0	0	0	0	6	39
65	0	0	0	1	3	17	0	0	0	0	7	39
70	0	0	40	3	3	30	0	0	21	6	21	57
75	0	0	56	3	10	41	0	0	35	6	39	93
80	0	17	96	5	23	53	0	6	42	26	52	93
85	5	96	96	18	46	53	1	41	43	49	93	93
90	96	96	96	53	53	53	42	43	43	93	93	93
Eastern Midwest												
50	0	0	1	0	0	11	0	0	0	0	0	36
55	0	0	4	0	0	23	0	0	0	0	3	57
60	0	0	23	0	1	31	0	0	2	0	6	79
65	0	0	49	0	6	43	0	0	13	0	15	88
70	0	1	82	1	14	50	0	0	32	4	45	92
75	0	23	95	5	31	52	0	2	43	13	79	93
80	4	73	95	13	48	52	0	28	44	51	92	93
85	58	95	95	44	52	52	19	44	45	92	93	93
90	95	95	95	52	52	52	44	45	45	93	93	93

TABLE 12. (Continued)

FGD Efficiency	PCC 1-1/2 inch, 1.6 s.g.			PCC 3/8 inch, 1.3 s.g.			PCC 1.6 s.g. on sink of 3/8 inch, 1.3 s.g.			0.9 pyritic sulfur removed		
	(Reduction Standard, %)			(Reduction Standard, %)			(Reduction Standard, %)			(Reduction Standard, %)		
	90	85	75	90	85	75	90	85	75	90	85	75
Western Midwest												
50	0	0	1	0	0	12	0	0	0	0	16	59
55	0	0	5	0	0	20	0	0	0	1	23	68
60	0	0	10	0	3	30	0	0	1	2	28	78
65	0	0	27	0	8	39	0	0	9	5	41	81
70	0	0	73	0	13	45	0	0	20	24	62	84
75	0	10	93	8	29	51	0	1	41	41	78	93
80	4	53	93	18	42	51	0	20	43	68	84	93
85	31	93	93	41	51	51	11	41	45	81	93	93
90	93	93	93	51	51	51	43	45	45	93	93	93
Western												
50	2	13	14	4	8	14	0	1	6	2	12	19
55	3	13	20	7	8	25	1	1	6	2	13	24
60	7	14	25	7	8	27	1	5	9	3	15	45
65	13	14	56	8	9	28	1	8	16	7	15	49
70	14	16	76	8	14	44	3	6	34	15	22	77
75	14	25	98	9	27	52	6	9	44	15	45	91
80	20	65	98	14	40	52	6	33	46	24	60	93
85	66	98	98	33	52	52	17	44	46	57	93	93
90	98	98	98	52	52	52	46	46	46	93	93	93
Entire U.S.A.												
50	1	5	8	2	5	14	0	0	3	1	7	31
55	1	6	13	4	6	23	0	1	4	1	9	42
60	3	6	21	4	6	29	0	2	6	2	13	59
65	5	6	45	5	10	35	0	3	14	4	19	67
70	6	9	71	6	15	45	1	3	20	11	36	82
75	6	21	96	9	29	52	3	6	41	16	59	91
80	12	63	96	17	42	53	4	27	44	40	74	93
85	53	96	96	38	53	53	16	42	44	72	93	93
90	96	96	96	53	53	53	43	44	44	93	93	93

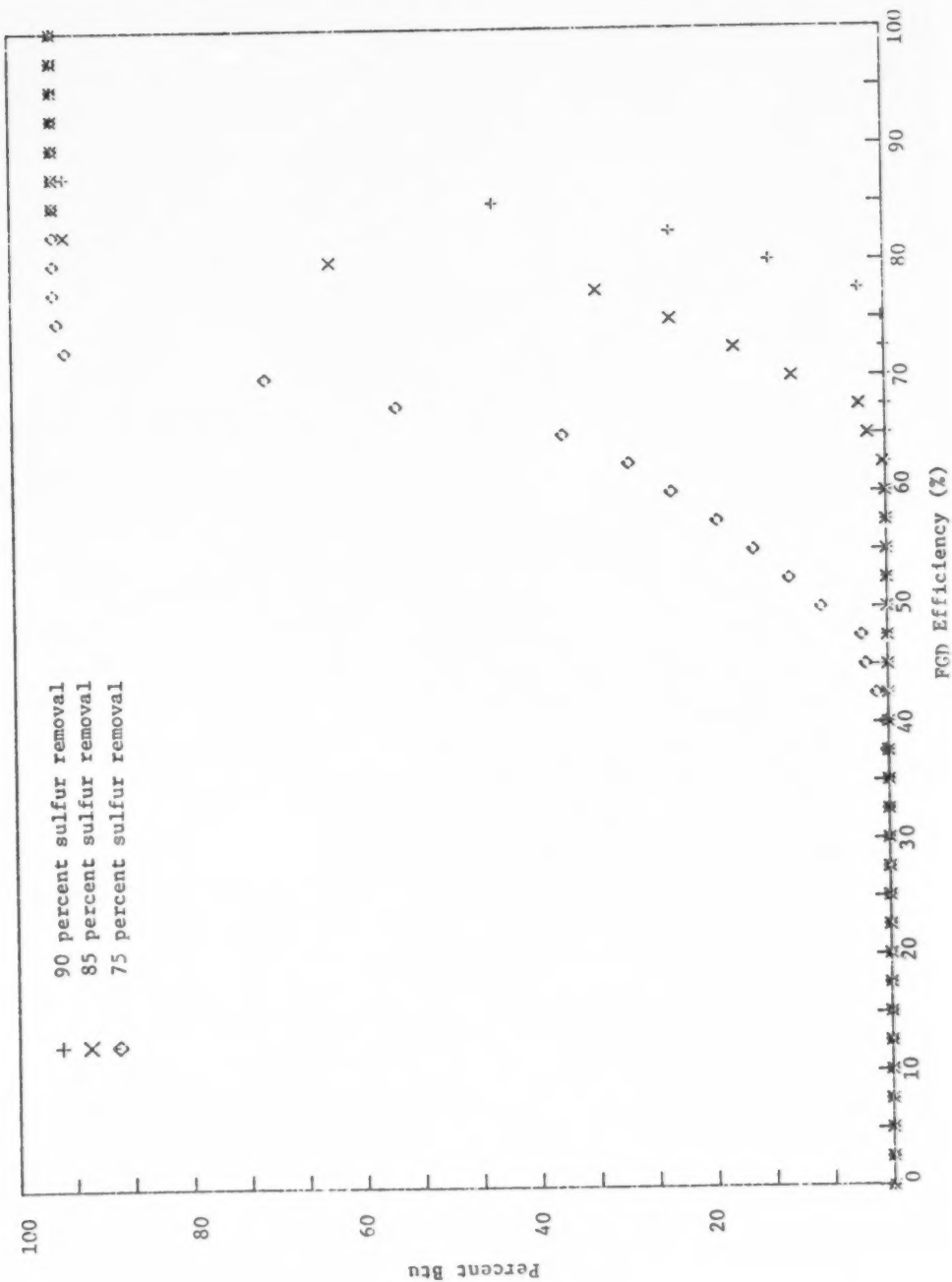


FIGURE 14. NORTHERN APPALACHIAN REGION; ENERGY AVAILABLE TO MEET 90%, 85%, AND 75% SULFUR REMOVAL STANDARDS FOR DIFFERENT FGD EFFICIENCIES IF PCC 1-1/2 INCH AT 1.6 SPECIFIC GRAVITY IS USED PRIOR TO COMBUSTION

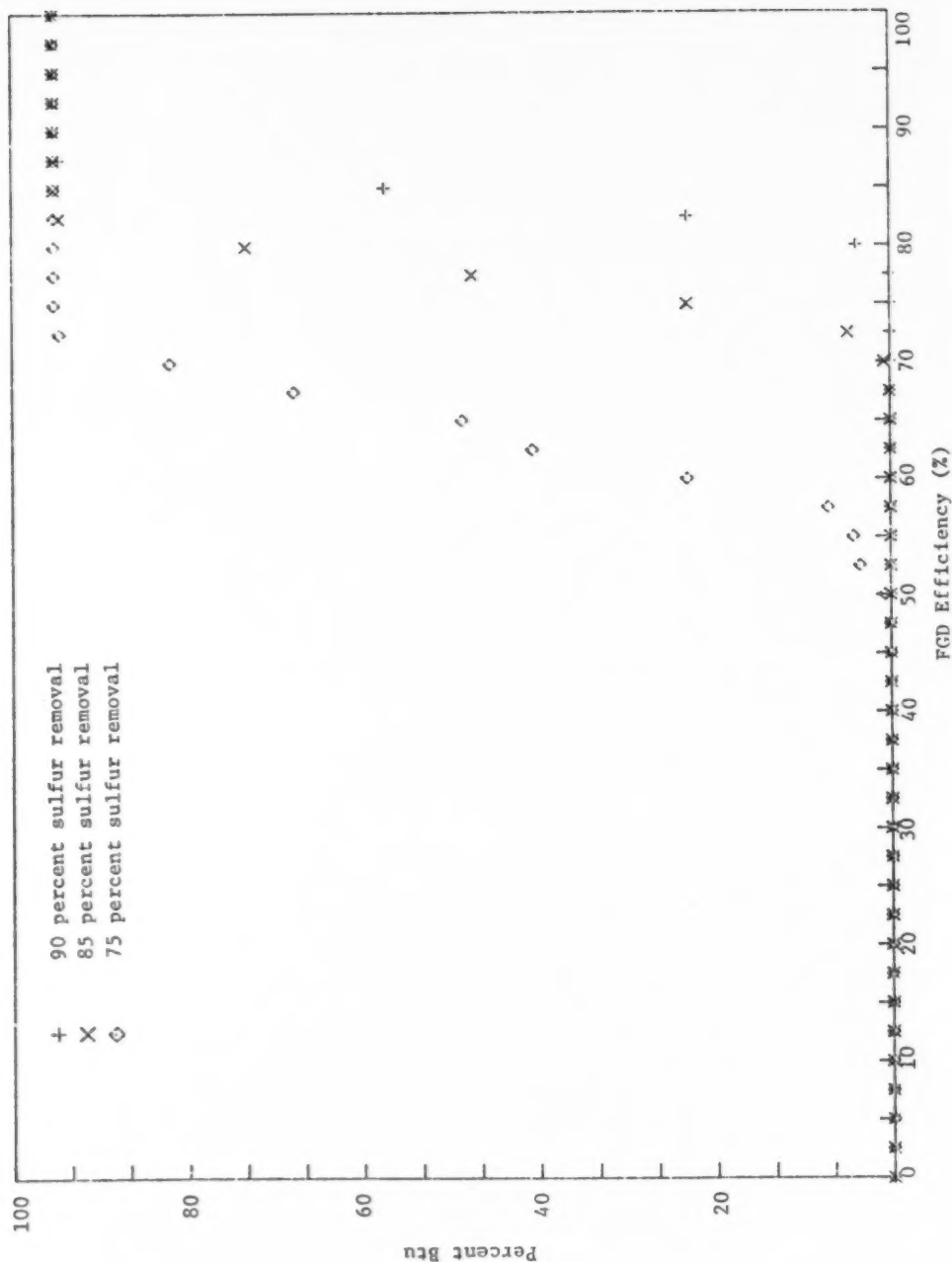


FIGURE 15. EASTERN MIDWEST REGION; ENERGY AVAILABLE TO MEET 90%, 85%, AND 75% SULFUR REMOVAL STANDARDS FOR DIFFERENT FGD EFFICIENCIES IF PCC 1-1/2 INCH AT 1.6 SPECIFIC GRAVITY IS USED PRIOR TO COMBUSTION

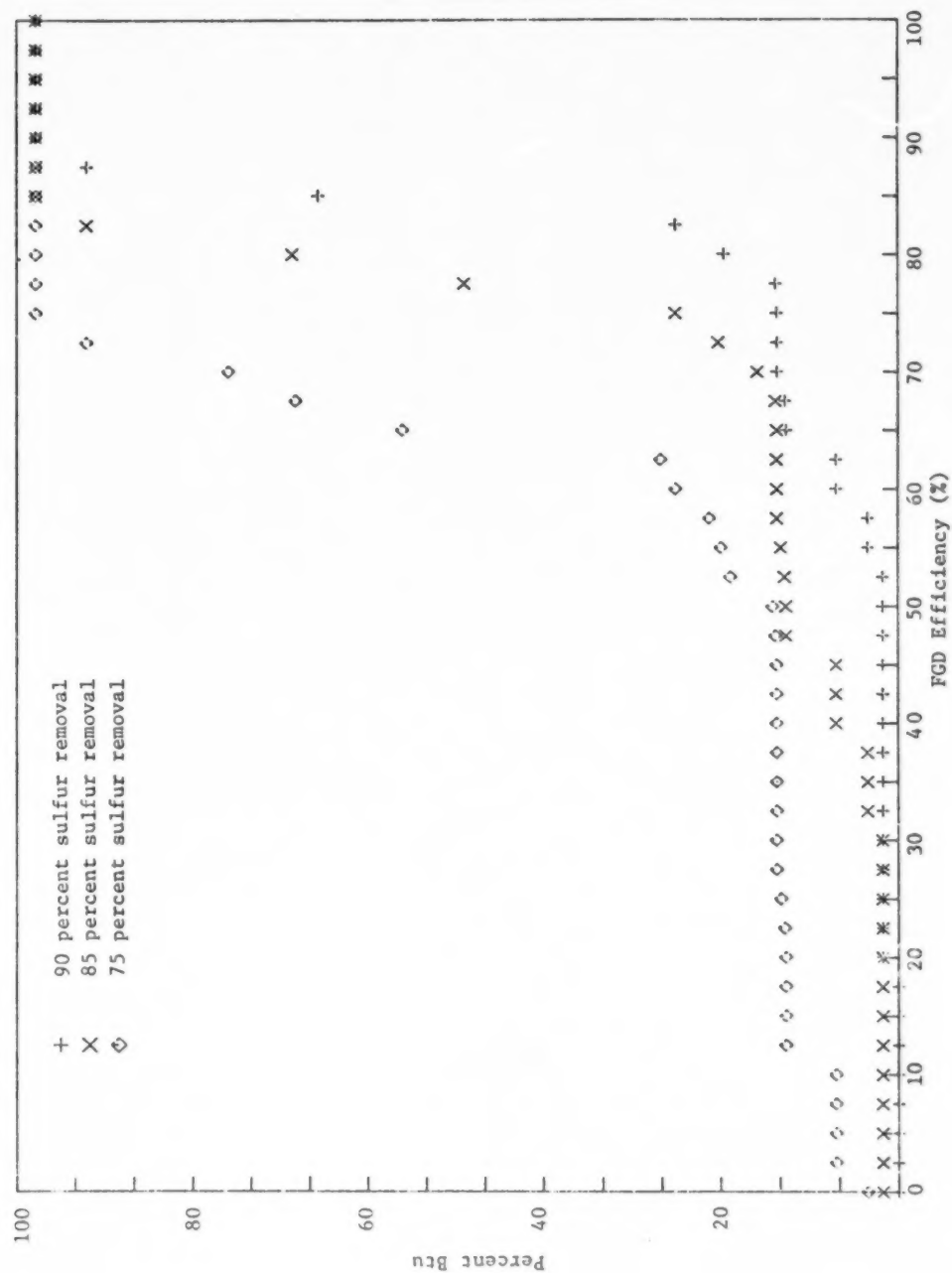


FIGURE 16. WESTERN REGION; ENERGY AVAILABLE TO MEET 90%, 85% AND 75% SULFUR REMOVAL STANDARDS FOR DIFFERENT FGD EFFICIENCIES IF PCC 1-1/2 INCH AT 1.6 SPECIFIC GRAVITY IS USED PRIOR TO COMBUSTION

The mathematical approach adopted allows the characteristics of the cleaned coal to be obtained from those of the raw coal by scaling the raw coal characteristics by factors dependent on the cleaning process involved and the washability analysis of the raw coal.

The data used in this study were as follows:

- 587 sets of washability analyses for coal from sample mines in the U.S. as reported by Cavallaro, Johnston, and Deurbrouck⁽³⁻²⁾.
- The reserve base of U.S. coal, consisting of 3,167 records specifying the weight of each resource for both strip and underground coal, together with the maximum, minimum, and mean levels of the major constituents of the coal in that resource. These data are consistent with those summarized in Thompson and York⁽³⁻³⁾ and Hamilton, White, and Matson⁽³⁻⁴⁾.
- Approximately 50,000 detailed sample coal analyses taken from the coal data base of the U.S. Bureau of Mines in Denver, Colorado. These data include the composition of each sample in terms of its ash, sulfur, and heat content.

Given these three sets of data as a starting point, the first step in the analysis was to overlay them into a single data base which contained 36,000 coal resource records and which had the following information for each:

- The location in terms of its region, state, county, and bed.
- The weight in tons of both strip and underground coal.
- The mean percent by weight of ash, organic sulfur, and pyritic sulfur.
- The mean heat content expressed in Btu/lb.
- The float-sink distribution of the coal characteristics.

The coal reserve resources and the washability data of RI 8118⁽³⁻²⁾ are each specified by state, bed, and county; however, there is not an exact correspondence between reserves and washability data because for many of the reserves there are no washability data. In order to be able to determine the desulfurization by physical cleaning processes of coal resources having

no washability data, the reserve resources were assigned washability data in the following manner:

- (1) If one or more state, bed, and county matches are found between a given reserve and the washability data, the reserve is assigned that washability data set which has coal composition closest (in the least squares sense) to the composition of the reserve. If no composition data are given for that reserve source, the resource is subdivided into as many parts as there are matching washability data sets and each part is assigned one of the washability analyses.
- (2) If there are no state, bed, and county matches between a given reserve resource and the washability data, look for state, bed, and region matches. Assign the reserve the matching washability data as in 1.
- (3) If no matches occur in either 1 or 2, look for state and county matches. Assign the reserve the matching washability data as in 1.
- (4) If no matches occur in 1, 2, or 3, assign the reserve the washability data from other beds in the same state and region as in 1.
- (5) For some states there are no washability analyses at all; reserve resources in those states are assigned washability data from other states in the same region as follows.
 - North Carolina is assigned washability data from Virginia.
 - Michigan is assigned washability data from all states in the Eastern Midwest region.
 - Texas is assigned washability data from Oklahoma.
 - South Dakota is assigned washability data from North Dakota.
 - Idaho, Oregon, and Washington are assigned washability data from Montana and Wyoming.The washability data of the relevant state or states is assigned to the resource as in 1.

Thus, all the coal reserve resources were assigned washability data.

The analytical data file consists of approximately 50,000 records, each of which gives coal composition data for a reserve resource sample. These sample analysis data were overlaid with the reserve base to obtain coal composition data for each reserve resource. Each resource has several sample analyses corresponding to it and, in the absence of any method of assigning weights to the different analyses for the same resource, all were weighted equally. The variation in the samples for a given resource was taken into account by dividing all the coal in that reserve resource into as many parts as there are corresponding sample analyses and each part was assigned the composition of one of the samples. For those reserves that have composition data given on the reserves file and on the analysis file, it was assumed that the mean of all the sample analyses should be equal to the composition data given on the reserves tape; if necessary, the sample analysis data were scaled to make this so. Reserves having no composition data given on the reserves file were assigned the coal composition given by the RI 8118⁽³⁻²⁾ washability data. Reserves having composition data given on the reserves file but no sample analysis used the coal composition given on the reserves file.

By overlaying the coal reserves file and the analysis file in this manner, an expanded reserves file of approximately 36,000 records was obtained, each record consisting of resource identification (by state, bed, and county), weight of coal for both strip and underground, and the composition of the coal. Only 36,000 records are obtained and not 50,000 as on the original analysis file because a number of the sample analyses either do not correspond to any of the reserve resources or correspond to a given resource which shows no coal available in both strip and underground reserve. For a given state, bed, and county group, there are several records on the file each having the same weight of reserves (such that the total adds up to the actual weight in the resource) but having possibly different composition data corresponding to the different sample analyses for that resource. The sulfur content of the coal is given in the coal reserves file and in the analysis file only as total sulfur content; this was divided into pyritic and organic sulfur in the ratio in which these two occur in the washability data that correspond to that resource.

To calculate the effect of the cleaning processes on the reserve resources, use has been made of the fact that a single washability analysis corresponds to many records on the overlaid reserves data file. By calculating in this fashion, the computational time required to perform this part of the analysis has been reduced by a factor of approximately 60. The methodology developed can treat any cleaning process that is of one of the following specific types:

- (1) A physical cleaning process
- (2) A chemical cleaning process that removes specified percentages of the characteristics of the raw coal (ash, pyritic sulfur, organic sulfur)
- (3) A chemical cleaning process that reduces the levels of the characteristics to given threshold values
- (4) Combinations of 1 and 3 or combinations of 2 and 3
- (5) A blend of the product coal from two of the above processes
- (6) One of processes 1-4 applied to the coal product of another of processes 1-4.

Reductions in the weight and Btu/lb of the coal by given percentages can be specified directly for processes of types 2 and 3 and for processes of type 1 as operating penalties over and above the reductions caused by the physical separation process. The RI 8118⁽³⁻²⁾ washability data are restricted to top sizes of 1-1/2 inches, 3/8 inch, or 14 mesh, and to fractions of float at specific gravities of 1.3, between 1.3 and 1.4, between 1.4 and 1.6, and the sink from 1.6.

A physical coal cleaning process can be specified by the top size to which the coal is crushed before separation plus the following quantities for each specific gravity fraction:

- The percent ash removed
- The percent pyritic sulfur removed
- The percent organic sulfur removed
- The percent Btu/lb recovery
- The percent weight recovery (= 0.0 for a specific gravity fraction which is discarded).

These quantities are in addition to the amount of each characteristic that is removed by the physical separation process. A cleaning process of type

2 can be expressed in terms of the above five quantities alone. A cleaning process of type 3 can be expressed in terms of the above quantities together with threshold values for those characteristics that are reduced to threshold levels.

Given such a specification of a cleaning process of type 1 or 2 and the file of the RI 8118⁽³⁻²⁾ washability data, it is possible to construct an array $T(i,j,k)$ which fully characterizes the cleaning of coal from a particular state, bed, and county group by the cleaning process. Here i corresponds to the index of the washability data (determined from the state, bed, and county group), j corresponds to the cleaning process under consideration, and k corresponds to the characteristics of the coal that are subject to change by cleaning (weight, ash, pyritic sulfur, organic sulfur, and Btu/lb). On cleaning by process j a sample of raw coal having state, bed, and county group correspondence to washability index i and characteristics $R(k)$, one obtains cleaned coal having characteristics

$$C(k) = R(k) \times T(i,j,k) \quad .$$

Thus, the effect of a cleaning process on coal of a given washability is obtained simply by scaling the characteristics of the coal by the relevant factors from the T array. Chemical cleaning which reduces characteristics to threshold values (type 3 processes) can be simulated by reducing the relevant characteristics after scaling by the T factors.

The array $T(i,j,k)$ is computed as follows. For a type 2 cleaning process j the specification of the process described above completely determines the T matrix. The process specification gives the proportion $D(k)$ of characteristic k of the feed coal that appears in the cleaned coal. If

- $k = 1$ corresponds to weight
- $k = 2$ corresponds to ash content
- $k = 3$ corresponds to pyritic sulfur content
- $k = 4$ corresponds to organic sulfur content
- $k = 5$ corresponds to Btu/lb for the coal

then

$$T(i,j,1) = D(1)$$

$$T(i,j,k) = D(k)/D(1) \quad , \quad k = 2,3,4,5.$$

This is independent of the washability index i .

For a type 1 process the proportion $P(\ell, k)$ of the feed coal in specific gravity fraction ℓ and having characteristic k that appears in the cleaned coal is given by the washability data for the feed coal. Any additional reduction in the levels of the characteristics is given by the process specification and can be expressed as $D(\ell, k)$. Combining these two, the proportion of the feed coal appearing in the product is

$$\sum_{\ell} P(\ell, k) \times D(\ell, k)$$

where the summation is taken for the four specific gravity fractions of the RI 8118⁽³⁻²⁾ washability data. Then

$$T(i, j, 1) = \sum_{\ell} P(\ell, 1) \times D(\ell, 1)$$

and

$$T(i, j, k) = \sum_{\ell} P(\ell, k) \times D(\ell, k) / T(i, j, 1) \quad , \quad k = 2, 3, 4, 5 \quad .$$

Once this T matrix is constructed from the specifications of the cleaning processes and the washability data, it is combined with the overlaid reserves and analytical data file. The characteristics of the raw coal from each of the 36,000 reserve resource records on the file are scaled by the appropriate factors from the T matrix to obtain the characteristics of that coal after cleaning by each of the processes. Any reduction in characteristic values to threshold values for a type 3 process is done at this stage. A new file is created consisting of 36,000 records as before but now each record contains not just the reserve levels and characteristics of the raw coal but those values also for the processed coal for each cleaning process. This file is then used to assess the desulfurization potential of the coal reserves.

Characterization of Coal Contracts

The existence of contracts for the purchase of coal may have an influence on decisions to adopt coal cleaning technology. This section presents a characterization of common coal contracts.

Approximately 80 to 85 percent of all U.S. utility coal is sold under long-term contract ranging from five to 40 years. Spot market purchases

represent the balance of all coal sales to utility companies. Some suppliers consider contracts lasting three or four years "spot" sales, but most limit the definition to arrangements of less than one year. Almost all utility contracts for western coal are long-term, generally for 20 to 30 years. Eastern and midwestern coal contracts are typically in the 10- to 15-year range, often with options to renew for five-year periods.

Most of the coal contracts in the commercial/industrial sector are for five years or less, primarily because of the relatively small steam coal requirements and the uncertainty of future coal demand for these businesses. Thus, most industrial coal agreements would not serve as a long-term contractual obstacle to physical coal cleaning (PCC).

At least four types of conditions may occur which would suggest adoption of PCC by a utility or industrial coal burner at an existing installation:

- Revision of State Implementation Plan (SIP) SO₂ emission standards, or tighter enforcement of existing SIP's, such that cleaned coal must be burned in order to meet the revised standards (Case 1).
- Recognition by the utility or industry that cost and/or technology changes have made physical coal cleaning clearly an economically attractive pollution control technique (Case 2).
- Promulgation of new regulations limiting the sulfur content of coals sold in selected regions (Case 3).
- Ruling to prevent economic disruption or unemployment (Case 4).

As a result of any of these scenarios, either singly or in concert, existing contractual arrangements between coal companies and users might be a critical factor in determining the users' response.

Revised or More Stringently Enforced SIP's

Clauses in coal supply contracts that deal with changed emission standards or enforcement thereof fall into one of three mutually exclusive categories:

- Early termination without penalty
- Early termination with penalty
- Take or pay.

The provision allowing early¹ termination without penalty is the most common of the three. It gives a coal buyer the right to cancel a long-term supply contract without penalty if changed government regulations make it impossible for the user to meet new standards with contract coal.

The clause allowing early termination with penalty deals with the problem of revised SIP's in a manner less favorable to the utility. Generally, these clauses have been written into some of the coal contracts signed within the last two or three years. Under this arrangement, the utility can terminate its supply contract in the event of changed government regulations which prevent it from burning contract coal, but it is required to pay the coal company a penalty unless that coal is resold.

The final type of arrangement, least favorable to the utility company, requires that the utility pay for all coal specified in its contract, even if it can no longer burn the coal due to changed government regulations. Some older contracts negotiated in the 1960s, before air pollution control regulations proliferated, were of this variety.

In the case of revisions or better enforcement of SIP standards, most parties would attempt to renegotiate their contract in order to avoid termination. In such event, PCC probably could be implemented by the parties if it were clearly the least costly alternative. The same outcome would result in the case of terminated contracts. Existing contractual obligations might bar its implementation, however, in two limited circumstances:

- If the coal contract contains a take-or-pay provision, the coal company may use that as leverage to refuse consideration of PCC and the utility may not breach its agreement.
- If the coal contract contains an early termination provision, the coal company may refuse to consider PCC, and the utility may value a continued relationship with a reliable supplier more than implementation of a less expensive pollution control technology.

Neither combination of circumstances is likely to occur frequently.

Cost and/or Technology Changes Favorable to PCC

Most coal supply contracts address only indirectly, in so-called "economic hardship" provisions, the case where PCC has become economically

desirable as all or part of an SO₂ control strategy. The clauses for this situation often have a very limited effect.

If PCC became economically desirable, it is probable that coal companies and utilities would renegotiate existing contracts to provide for its implementation. The utility may have to finance a large percentage of the undertaking. In the few cases where physical coal cleaning was not feasible from a supplier's perspective, existing long-term coal supply contracts would serve as an obstacle to PCC because it is improbable that many utilities would break these contracts.

Regulations Limiting Sulfur Content of Coals Sold in Selected Regions

Price adjustment clauses to protect the supplier would be applicable to a regulation limiting the sulfur level of coals. Since utility coal agreements historically have been long-term, it always has been necessary to specify carefully the ways in which the base contract price would rise over time to reflect accurately increased mining costs (whether caused by economic factors or government intervention). Price adjustment provisions address a wide range of cost components. The ease with which a coal cleaning investment could be passed along via price adjustment and fuel adjustment mechanisms may render this a relatively attractive option to the parties involved. Thus, price adjustment clauses might actually encourage the PCC option in the case where the sulfur level of coal is limited.

Ruling to Prevent Economic Disruption or Unemployment

Section 125 of the Clean Air Act Amendments of 1977⁽³⁻⁵⁾ provides for action by a governor, the EPA Administrator, or the President to prevent or minimize significant local or regional economic disruption or unemployment which would otherwise result from use by a utility of coal other than locally or regionally available coal. Under such conditions, each affected utility may be required to enter into long-term contracts, of at least 10 years in duration, for regionally available coal and to enter into contracts to acquire any additional means of emission limitation which may be necessary to meet emission standards. Thus, if a state produces

only high-sulfur coal, such a ruling under Section 125 may be necessary to prevent large-scale unemployment of its miners. A ruling of this type should encourage use of PCC within the state, but if coal cleaning would not lower sulfur emissions sufficiently, other supplemental SO₂ emission control techniques might be required as well.

Problem Areas

Only two situations have been postulated where regulations that might be imposed by the Federal government could place either or both parties to a coal supply contract in a completely untenable position. First, it has been suggested that the Government could go so far as to prohibit the burning of a high-sulfur-content coal in the geographical area in which it was currently being used. If this prohibition were sufficiently stringent, it would preclude the use of the contract coal either in the raw or cleaned state. One or the other of the contractual parties then could be placed in an untenable economic situation. The only recourse would be through the courts to the other party or to the Government or to both.

Second, if a ruling of "economic hardship" were imposed, as provided in Section 125 of the 1977 Clean Air Act Amendments⁽³⁻⁵⁾, then a utility in the affected state might be forced to abrogate a contract for coal from an out-of-state source. But, the resolution of this situation is unclear because of the provision in the Act that "any such action by the Government . . . shall take into account the final cost to the consumer of such an action." There is no further guidance in the law and the conflict can be stated thusly: If out-of-state coal were permitted to be the means of diminishing sulfur oxide emissions, then the "economic hardship" would be borne by the coal mine owners and particularly by the coal miners in the affected state. On the other hand, if flue gas desulfurization were the means used to permit control of emissions from the burning of high-sulfur in-state coal, then the significant cost of this means would be passed through to the consumers by the utilities and this would cause "economic hardships" as well.

In every other situation considered, and particularly where physical coal cleaning is the preferred SO₂ control option, the resolution of contractual differences by prudent and reasonable parties is highly probable.

Coal-Burning Installations Data

As further background information, Appendix D presents data on coal-burning installations. Data are given on the number, size, age, location, and applicable emission regulations. Information is included for both boiler and nonboiler uses of coal.

References for Section 3

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SECTION 4

STATISTICAL INTERPRETATION OF SULFUR EMISSIONS

Regulations promulgated by the U.S. Environmental Protection Agency for the Federal government and by the various states call for an upper limit on the stack gas emissions of sulfur dioxide (SO_2) by coal-burning power plants. Although there are various upper limits established depending upon whether they are imposed by the Federal or state governments, whether they apply to new or old facilities, the regulations are often not explicit in defining whether these limits can not be "instantaneously" exceeded or whether these limits refer to short- or long-term averages which are not to be exceeded. Also, it has proven difficult to interpret properly the required properties of the coal, as to sulfur contents and heating values needed to comply with the specified regulations. Thus, it is the purpose of this discussion to clarify the problems involved and to explain clearly and rationally the relations which exist between coal sulfur contents and meeting emission regulations for SO_2 .

No one should have any great difficulty in understanding the principles of a perfect system operating on an instantaneous basis; it is only when the variables associated with time are introduced that the performance of the system evades understanding and evaluation becomes impossible. In the perfect system, coal of a known, specific sulfur content is introduced into a combustion chamber, combustion takes place, and the products of combustion are expelled. These products of combustion are solids (called ash), gases, and sometimes liquids. The sulfur contained in the coal, not often as the elemental form but generally as organic and inorganic compounds, distributes itself between the ash constituents and the combustion gases. The major product formed is SO_2 , which is a gaseous component of the combustion gases. Even though a small percentage of the sulfur content (5 to 15 percent) of the coal combusted is contained in the resulting ash, it will be assumed for the purpose of this discussion that all the coal sulfur is converted, or that a constant percentage of the coal sulfur is converted, to SO_2 . In either of these cases, the statistical characteristics of coal sulfur and coal sulfur emissions are equivalent.

Emission Standards

Limits on sulfur oxide emissions, as regulated by Federal or State laws have in the past been interpreted as specific maximum emission limits which are "never to be exceeded". An example of this is the Federal 1971 New Source Performance Standard (NSPS), which called for a maximum emission limit of 1.2 lb SO₂/10⁶ Btu. With fixed limits such as these, the manner in which coal sulfur levels should be determined to assure meeting these limits is not overly complex, but consideration must be given as to whether individual sulfur level measurements are correlated or random in nature.

In contrast, the new New Stationary Sources Performance Standards (NSSPS) promulgated June 11, 1979, calls for a percentage reduction (90 percent for high sulfur eastern coal) of the potential SO₂ emissions. The emissions and percentage reduction requirements are to be met for a 30-day rolling average. Now, not only must an average sulfur level and the variability of sulfur values be determined, but also consideration must be given to the time variability of SO₂ levels and SO₂ reduction in evaluating whether the standard is being met. This revised requirement further complicates the interpretation of the influence of sulfur variability on meeting the specified emission regulation.

Considerations of Sulfur Variability

The variability of sulfur in coal poses special problems for the control of emissions. If the input coal stream to a boiler has a 24-hour average level of SO₂ (per million Btu) that is equal to the 24-hour emission limit, then approximately half of the 24-hour time intervals will have emissions that exceed the emission limit. To assess the proportion of time within compliance, it is convenient to consider the following measure:

$$Q = \frac{L - \bar{x}}{s} , \quad (1)$$

where L denotes the emission limit, $\bar{x}$ denotes an average value of sulfur emission, taken over a specified time interval, and s denotes the standard deviation among the $\bar{x}$ -values. Negative values of X indicate that the average sulfur emissions exceed the regulation limit for most of the time

intervals; a Q-value of zero indicates compliance approximately half of the time intervals; large positive Q-values indicate compliance a large percentage of the time intervals. In this manner, the Q-value can be regarded as a compliance index. In simple terms, it is seen that the Q-value represents the "distance" between the emission limit and the average sulfur emission for a specified time interval, where the distance is measured in units of the standard deviation of the sulfur emission values for these time intervals.

Several conclusions can be drawn from the form of the Q-index. Suppose, for example, that the average sulfur emission is reduced without changing the standard deviation; that is, $\bar{x}$ decreases and s remains fixed. Equation (1) shows that, under these conditions, Q will increase so that compliance would be improved. Thus, for fixed x , reductions in the level of SO_2 emissions always enhance compliance.

It is sometimes erroneously stated that to improve compliance it is necessary to reduce $\bar{x}$. Equation (1) shows, however, that if a reduction is made in the standard deviation, improved compliance can result, even if the value of $\bar{x}$ remains unchanged. In other words, for positive Q -values, any reduction in sulfur variability will also yield improved compliance even though the average sulfur level remains fixed. Of course, if both $\bar{x}$ and s are reduced, for example, by coal cleaning, then the compliance index can increase dramatically.

As noted previously, large positive values of Q are desirable for compliance with emission standards. The proper magnitude for Q can be partially assessed by making assumptions concerning the statistical properties of $\bar{x}$ and s . Although most sulfur emission data for coal burning are auto correlated (i.e., current sulfur emission values are related to previous values) the importance of variability can be illustrated by assuming that each observation is independent. For example, if the $\bar{x}$'s are assumed to be independent, normally distributed values, then a Q -value of 2.0 corresponds to a 2-sigma limit and may be associated with 97.7 percent of the $\bar{x}$'s expected to be in a state of compliance; a Q -value of 3.0 corresponds to a 3-sigma limit with 99.9 percent of the $\bar{x}$'s expected to be in compliance; a negative Q -value of -0.5 indicates that 69.2 percent of the $\bar{x}$'s are expected to be out of compliance, etc. Disregarding, for the moment, the 90 percent reduction requirements, the 1979 NSSPS for utility boilers

permit three 24-hour averages to exceed the emission ceiling each month. Based on a 30-day month, it follows that 27 out of 30 $\bar{x}$'s must be less than the limit, so that 90 percent of the daily $\bar{x}$'s must be less than the limit. Under the normality assumptions stated above, this requirement corresponds to a Q-value of 1.28. Expressed as an inequality constraint for compliance, Equation (1) may be expressed as follows:

$$\bar{x} + Qs \leq L, \quad (2)$$

and for the proposed standard, this becomes

$$\bar{x} + 1.28s \leq L.$$

In the 1979 NSSPS, L has a maximum value of 1.2 lb SO₂/10⁶ Btu; between 1.2 and 0.6 lb SO₂/10⁶ Btu, a value of 0.1 the value of 1 lb SO₂/10⁶ Btu in the raw coal; and below 0.6 lb SO₂/10⁶ Btu, a value of 0.3 the value of 1 lb SO₂/10⁶ Btu in the raw coal.

The relative standard deviation (RSD), the ratio of s to $\bar{x}$, is often used as a measure of sulfur variability. There are several good reasons for this choice: (1) the RSD is often found to be more "stable" than other statistical measures; (2) because the RSD is expressed as a percentage of the mean SO₂, it can be easily applied to coals having different mean values for SO₂; and (3) as a "noise-to-signal" ratio, the RSD reflects the intuitive idea that the standard deviation is a measure of noise and the mean is a measure of signal. To offset partially these advantages, however, the RSD has several disadvantages. For example, it represents the ratio of two random variables $s/\bar{x}$, so that variations in the RSD may result from variations in either the numerator s , or the denominator $\bar{x}$, or both. For this reason, the statistical distribution of the RSD is complex and clearly depends on both the statistical distribution of s and the statistical distribution of $\bar{x}$.

Because of the relative structure of the RSD, it is not easy to compare two different RSD's. For example, suppose that the mean $\bar{x}$ and standard deviation s of the sulfur levels are both decreased for the cleaned coal. Let $\bar{x}_1$, s_1 , and $\bar{x}_2$, s_2 denote the respective values before and after cleaning. If the mean is reduced appreciably more than the standard deviation is reduced, then the RSD can actually increase as a result of

cleaning the coal. That is, after cleaning the $RSD_2 = s_2/\bar{x}_2$ can exceed $RSD_1 = s_1/\bar{x}_1$, even though $s_2 < s_1$ and $\bar{x}_2 < \bar{x}_1$. As a numerical example, in lbs of SO_2 per million Btu, let $\bar{x}_1 = 4.8$ and $s_1 = 0.24$ before cleaning and let $\bar{x}_2 = 1.2$ and $s_2 = 0.12$ after cleaning. These values show that $RSD_2 = 0.12/1.2$ is 10 percent after cleaning, whereas $RSD_1 = 0.24/4.8$ is found to be only 5 percent before cleaning. This example serves to illustrate the fact that the RSD does not reflect the external emission limit. Because the RSD increases as a result of coal cleaning, it would be incorrect to conclude either that the sulfur variability increases as a result of cleaning the coal or that compliance with standards is more difficult. Both of these errors can be corrected by examining the relation between the RSD and the index of compliance Q or by always using the RSD and mean values jointly.

To show the relation between RSD, the mean sulfur value and the Q-index, the inequality constraint for compliance, Equation (2), may be expressed as shown:

$$\begin{aligned} \bar{x}[1 + Q(s/\bar{x})] &\leq L \\ \text{or} \quad \bar{x}[1 + Q(RSD)] &\leq L. \end{aligned} \quad (3)$$

This expression shows the compliance relationship that must be satisfied by $\bar{x}$, RSD, L and Q. In this form it is seen that the left side of Equation (3) is reduced if (1) $\bar{x}$ is reduced and the RSD remains constant; or (2) the RSD is reduced and $\bar{x}$ remains constant. Less obvious, but possible situations result when (3) the value of the RSD increases but the increase is more than offset by a decrease in $\bar{x}$; and (4) the value of $\bar{x}$ increases but it is more than offset by a decrease in the RSD. The first and third cases can be reasonably associated with the possible effects of coal cleaning.

In discussions of the variability of sulfur in coal, it is the inherent variability of the sulfur that should be of primary concern. However, the statistical measures of the sulfur level and its variability tend to become obscured by the fact that statistical estimators are frequently affected by the sampling process, the volume of coal represented by the sample, the location of the coal in the coal seam, etc. Statistical methods provide a wide variety of measures of average sulfur level (time average, space average, arithmetic mean, median, etc.) and of variability (standard deviation, range, RSD, etc.). Unfortunately, these measures are often used incurantly. In addition to wrong assumptions, biases, etc., they are

TABLE 34. MACHINERY NOISE REDUCTION MEANS⁽⁷⁻¹⁵⁾

Equipment	Noise Reduction Means	Potential Problems
Screens	Rubber decking	Wear, material movement Material flow rate
	Slow shaking mechanism	
	Better gearing for shaking mechanism	Cooling, maintenance
	Enclosure for shaking mechanism	
	Improved supports	Working access, inspection
	Screen enclosure	
Chutes	Interior ledges	Material flow obstruction
	Rubber linings	Wear, repairability
	Concrete liners	Wear, repairability
	Exterior damping	Wear, repairability
Hoppers, Bins	Keep nearly full	Interferes with operation
	Rubber linings	Wear, repairability
	Exterior mass	Weight, supports
Crushers	Better gearing	Access for inspection, repair
	Enclosure	
Car Shakeouts	Replace with rotary dump	Compatibility with plant and cars
	Operator enclosures	Working convenience
Picking Tables	Replace with rotary breaker	Compatibility with plant: community noise
	Partial enclosures for workers	Work convenience
Blowers, Fans, Valves	Mufflers on intakes	Exterior noise
	Duct to plant exterior	
	Enclosing casing	
Vacuum Pumps	Mufflers on exhaust	
	Duct to plant exterior	
	Enclosure for separator tank	
Air Blasts	Replace nozzle	Reduce efficiency
Liquid Pumps, Dryers, Motors	Enclose body	
Feeders	Replace electromechanical with mechanical	Compatibility
	Add noise barriers	Access

Trace Elements and Control

Potential Pollutants. Coal preparation is used to remove contaminants from coal that are present as discrete phases and separable from the organic portion of the coal. Therefore, it is not expected that the trace elements Ge, Be, and B, known to be associated with the organic portion of coal, will be removed. Furthermore, only a small portion of the trace elements, P, Ga, Ti, V, and Sb, which are more closely associated with the organic material rather than with the mineral matter in raw coal, would be expected to be removed by coal preparation. Those elements typically associated with the mineral sulfides and carbonates, but also found in the organic material, would be expected to be partially rejected by physical cleaning methods (i.e., Co, Ni, Cr, Se, and Cu). Finally, the trace elements Hg, Sn, Cr, As, Pb, Mo, and Mn, which are closely associated with mineral matter, would be expected to be reduced significantly by coal preparation⁽⁷⁻¹⁶⁾.

Trace elements may be released into the environment from coal-processing wastes as dissolved or suspended materials in the drainage from waste dumps. Typically, acid drainage from coal refuse contains high concentrations of Fe, Al, Ca, formed Mg, and SO_4 ions, which are derived from the major minerals. The acid formed may also solubilize a number of the less abundant or minor elements in coal preparation wastes⁽⁷⁻¹⁷⁾. Moreover, there is considerable evidence that coal refuse dumps will continue to produce significant quantities of waterborne contaminants for many years after their construction.

It is widely known that coals contain a number of trace elements which may be converted to volatile forms during combustion. However, few studies have addressed the problem of trace element contamination from burning coal refuse piles. In 1974, a study by Finkelman et al.,⁽⁷⁻¹⁸⁾ at the USGS demonstrated that a large number of trace elements, many of which are toxic, are transported from the hot zone with the other combustion products and subsequently deposited in cooler areas of the waste pile⁽⁷⁻¹⁷⁾. But these phenomena are not fully understood and deserve further investigation.

Control Methods. Trace elements in acid drainage from coal refuse materials can be controlled by either preventing formation of the acid drainage or treating the acid drainage once it has formed. Various techniques for the

prevention of acid drainage have previously been discussed (see control methods for water pollution and solid waste pollution). Although these control measures are often only peripherally directed at trace elements, the trace element content of acidic waters may be affected to varying degrees by these methods. Most techniques for acid drainage control are directed primarily at neutralizing the acidity by the addition of an alkaline material^(7-17,7-19). By properly selecting the alkaline agent, many metals can be removed during neutralization as insoluble hydroxides. Alkaline agents include lime, limestone, caustic soda, and soda ash⁽⁷⁻¹⁹⁾.

With care and attention to sound engineering practices, waste pile fires can be almost entirely prevented, thus eliminating the potential for trace element contamination from this source. Preventive measures include proper grading and compacting or sealing of the waste pile perimeters to reduce the flow of air through the bank. However, success in controlling refuse fires once they have begun is rather limited. The most effective method has been to dig out the burning materials and allow them to cool at the surface. Other fire control methods for these wastes include sealing the piles with soil or other materials to control air circulation or injecting slurries to smother the burning waste⁽⁷⁻¹⁷⁾.

Some work has been reported on the utilization of metals or minerals from coal refuse materials^(7-20, 7-21). Among the major materials that have been sought from coal wastes are S and Al. Processes for recovering minor elements such as Ga, Ge, Mn, and Mo have also been developed. Among the most promising techniques for recovering useful materials from coal refuse are magnetic separation, ion exchange, and roasting and leaching methods⁽⁷⁻¹⁷⁾.

Summary: Net Environmental Effects

Through coal preparation, highly mobile air pollutants which may be discharged by the burning of raw coal may be transferred into solid refuse or wastewater streams. In these forms the pollutants may be easier to control than as air pollutants. On the other hand, the waste materials generated from coal preparation can themselves be important sources of environmental contamination. At present, environmental control is technically feasible for most

of the waste streams emanating from coal preparation plants. Frequently, however, the control devices or techniques used may lead to new pollution problems.

Several types of air pollution control devices for both particulates and gaseous products are available for application to preparation plant discharges. Fugitive dust emissions from the preparation plant, coal storage, transportation facilities, and handling operations can also be controlled by a number of techniques. However, often the disposal of waste particulates collected by an air emission control device can present new potential problems. For instance, the collected solids from control devices for crushing and sizing operations may have high concentrations of impurities and require separate disposal⁽⁷⁻²⁾.

Water pollution problems resulting from process water discharge and/or acid drainage are controllable by a number of clarification and treatment techniques. However, improper disposal of the solid waste following water clarification and treatment may result in acid water drainage or accidental overflows at settling ponds. Furthermore, the flocculants used in the water treatment may themselves affect water quality⁽⁷⁻¹⁾.

The problems associated with solid waste from preparation plants arise from the inherent qualities of the coal as influenced by the characteristics of the coal seam, the preparation method employed, the terrain available for the disposal site, and the construction controls applied. These factors exist in a complex interrelationship. Although control methods are available, the potential for pollution from solid waste disposal will likely remain.

With the use of proper control methods and "good housekeeping", noise pollution should not present a problem at the coal preparation plant or to surrounding communities. Noise control can be accomplished by removing the affected person from the noise source, surrounding the noise source with enclosures, obstructing the noise path, or providing safety devices to those working in noisy areas.

Although there are no direct control methods being applied for trace elements in coal waste discharges, the control methods for acid drainage and waste pile fires seem to indirectly resolve most contamination problems from trace elements. The ultimate fate of these elements, however, has received only limited attention and is still not well defined.

Flue Gas Desulfurization

The primary function of flue gas desulfurization (FGD) is to transfer SO_2 from the flue gas into the scrubber liquid. The scrubbing process is similar to the process occurring in a rain storm where the falling liquid droplets wash or scrub the gas. Flue gas desulfurization systems can be divided into two general categories: nonregenerable and regenerable. Non-regenerable systems produce a sludge that must be disposed of by dewatering followed by landfilling or ponding. These systems utilize lime or limestone as the major reactant because of their relatively low cost and wide availability. Of today's construction commitments, 70 percent are for the non-regenerative lime or limestone systems. Regenerable FGD systems recover a product, such as sulfuric acid or elemental sulfur, which may have a value.

The following discussion briefly describes the potential pollutants and control methods for various FGD systems.

Nonregenerative Processes

Five throwaway (or nonregenerative) processes have gained some degree of user acceptance in the United States. These processes include wet limestone scrubbing, wet lime scrubbing, alkali scrubbing without regeneration, alkali scrubbing with calcium regeneration, and dilute acid scrubbing. All of these processes produce calcium-sulfur compound sludges with the exception of sodium alkali scrubbing without regeneration.* Because lime and limestone scrubbing are the predominant nonregenerative systems being used and planned for future installations, the following discussion is limited to these two systems.

By-Product Disposal. One of the major problems inherent in FGD systems based on lime or limestone is the necessity to dispose of or utilize large

* Sodium alkali scrubbing without regeneration produces water soluble Na_2SO_3 and Na_2SO_4 which are difficult to dispose of in an environmentally acceptable manner. However, alkali scrubbing with calcium regeneration (double alkali process) avoids this soluble salt disposal problem by reacting the scrubber effluent with limestone and/or lime to precipitate calcium sulfite and sulfate. The precipitated solids are sent to a vacuum filter for separation, and the waste disposal problem becomes one of calcium sludge disposal. Dilute acid scrubbing after neutralization produces gypsum, which, when not marketable, should be considered as merely a calcium-sulfur compound sludge.

quantities of sludge. At present, lime/limestone scrubbing systems generate a sludge with little commercial value. Typically, the sludge contains $\text{CaSO}_3 \cdot 1/2 \text{H}_2\text{O}$, $\text{CaSO}_4 \cdot \text{H}_2\text{O}$ and CaCO_3 ⁽⁷⁻²³⁾. Furthermore, the sludge may contain dissolved solids and heavy metals originating from the coal, lime, or limestone, and to a lesser extent the make-up water for the scrubber system. For coal-fired installations where efficient particulate removal is not installed upstream of the absorber, the sludge may also contain large quantities of fly ash. Generally, the sludge has the consistency of toothpaste or heavy mud, and may behave like quicksand indefinitely unless fixation is used⁽⁷⁻²⁴⁾.

The amount of sludge generated by a given plant is a function of the sulfur and ash content of the coal, the coal usage, the on-stream hours per year (load factor), the mole ratio of lime or limestone added in relation to the amount of SO_2 removed, the SO_2 removal efficiency, the ratio of sulfite to sulfate in the sludge, and the percent moisture in the sludge⁽⁷⁻²³⁾. Moreover, the amount generated can be significant. For example, it is estimated that in 1980 a 1000-MW coal-fired generating plant will produce annually 1.4 million tons of sludge and ash (combined disposal), 50 percent solids, with a lime/limestone flue gas desulfurization system. It is further estimated that by 1980, a total of 130,000,000 tons/year of wet sludge and ash (limestone sludge, combined disposal, and 50 percent solids) will be generated by lime/limestone wet scrubbing systems. This estimate assumes that FGD control will most likely be installed on 90,000 MW, or about 35 percent of the total coal-fired utility generating capacity by 1980⁽⁷⁻²⁵⁾.

Several FGD sludge handling schemes are currently used and/or planned by utilities. To minimize disposal problems, sludge treatment processes such as dewatering, oxidation, and fixation are often employed. Following this initial treatment, the material can be conveyed by a number of modes (i.e., pipeline, truck, barge, conveyor belt) to a suitable retention site and/or further utilized.

Currently, ponding and landfilling are the only methods practiced by the utilities for the disposal of lime/limestone sludges. Other potential disposal methods include abandoned mine filling, deep well injection, and ocean disposal. The problems associated with ponding and landfilling, however, are becoming increasingly difficult. For example, the pond volume requirement for lime/limestone sludge is larger than that required for fly ash disposal because

of the larger packing volume of the former. The ratio of calcium sulfite to calcium sulfate is significant to the packing volume. Sulfites tend to crystallize into small, thin platelets which settle to a loose bulky structure that may include a relatively large amount of water. The net result is to increase the land required for disposal. For instance, the disposal of lime/limestone sludge for a typical 1,000-MW coal-fired installation will require between 30 and 60 acres per year ponded to a 10-foot depth. The lower figure (30) represents the area required for sulfate sludge, while the higher figure (60) represents the area required for sulfite sludge⁽⁷⁻²⁶⁾.

Many other problems are also associated with the ponding and landfilling of FGD sludges. The land use for waste disposal may be aesthetically objectionable. Depending upon the site, the sludge could provide varying degrees of surface and groundwater pollution. Moreover, some wastes are very resistant to dewatering and could reslurry in the pond or landfill.

Potential Environmental Impacts. The potential water pollution problems derived from the chemical-physical properties of scrubber sludges may include problems from: soluble toxic species, chemical oxygen demand, excessive total dissolved solids, excessive levels of specific species (i.e., sulfate and chloride are not generally thought of as a toxic), excessive suspended solids, and the thixotropic (quicksand-like) nature of the sludge⁽⁷⁻²³⁾. In addition, the major characteristic affecting disposal and potential pollution is the relative amount of sulfite and sulfate in the sludge. For instance, if the sulfur in the sludge is in the form of sulfite (reduced form), then chemical oxygen demand (COD) and trace metal contamination levels may be unacceptably high, dewatering may be a problem, and thixotropic hazards may exist with the disposed sludges. On the other hand, if the sulfur is in the form of sulfate (oxidized form), there is greater potential for trace metal contamination and total dissolved solids may be a problem; however, COD, dewatering problems, and thixotropic hazards should be absent.

Current research by the Aerospace Corporation⁽⁷⁻²⁷⁾ on five different scrubber sludges has revealed the need for protection of ground and surface waters because of excess (concentrations higher than drinking water standards) chlorine, sulfate, and several trace elements. The trace contaminant concentrations observed to be above water quality standards were As, Cd, Cr, Pb, Hg, Se, sulfite, and B. Furthermore, Bern⁽⁷⁻²⁸⁾ has run basic leach studies

on six different scrubber sludges. The results indicated fairly high total dissolved solids in the range of 1049 to 1783 mg/l. Other leachability studies have also reported leachate from scrubber sludges containing total dissolved solids of 1000 to 2000 mg/l, a possible chemical oxygen demand, a toxic impact from sulfite with concentrations ranging from 0.1 to 20 mg/l, and possible contamination of Zn and Pb ions. Nevertheless, a study by the Radian Corporation⁽⁷⁻²⁹⁾ demonstrated that a high adsorptive soil would provide significant protection from groundwater contamination by scrubber leachate.

By-Product Utilization. An alternative to the disposal of scrubber sludges is development of commercially applicable utilization processes. Numerous programs in this area have been conducted through government sponsorship and by industry^(7-25,7-27). The utilization processes developed from these efforts are summarized in Table 35. It should be noted that although these utilization options have been shown to be technically feasible, most lack economic feasibility because they are not competitive with other methods producing the same or similar materials⁽⁷⁻²²⁾. Some of the utilization processes that have been demonstrated on a relatively large scale are the recovery of pozzolanic, autoclaved, and gypsum products. Other less developed processes include production of mineral wool, extraction of sulfur by microbial degradation, reclamation of strip mines, and soil amendment.

Regenerative Processes

Flue gas desulfurization processes that recover sulfur in some form are being tested around the country in large scale units. These processes vary widely in design and raw materials. Furthermore, the byproducts may be either sulfuric acid, elemental sulfur, or ammonium sulfate⁽⁷⁻²²⁾.

Presently, there is only one case where a regenerative process is being implemented by a utility. Public Service of New Mexico is installing sodium scrubbing-thermal regeneration (Wellman-Lord Process) on two boilers. Although use of a recovery process may lead to a larger direct cost, eliminating the sludge disposal problem gives it a major advantage. It should be pointed out, however, that even with recovery, power plants still will have a major waste

TABLE 35. SLUDGE UTILIZATION SCHEMES (7-23)

I.	<u>Filler Material</u>
	A. Structural Fill
	B. Mine Void Fill
	C. Filler in Bituminous Concrete
	D. Waste Disposal/Sanitary Structural Landfill
II.	<u>Pozzolan Products</u>
	A. Road Base Course
III.	<u>Autoclave Products</u>
	A. Concrete Admixture (Structure and Products)
	B. Fired Brick
	C. Lightweight Aggregate
IV.	<u>Pressure Sintered Products</u>
	A. Coatings for Metal
	B. Pipes
V.	<u>Gypsum Products</u>
	A. Plaster
	B. Wallboard
VI.	<u>Soil Amendment</u>
VII.	<u>Mineral Wool</u>
VIII.	<u>Mineral Recovery</u>
	A. Lime
	B. Aluminum
	C. Iron
	D. Pozzolan (glass particles)
	E. Titanium
	F. Silicon
	G. Rare Elements
IX.	<u>Sulfur Extraction</u>
	A. Sulfur
	B. Sulfuric Acid
X.	<u>Polluted Water Treatment</u>
	A. Recovery of Polluted Streams, Ponds, Lakes
	B. Neutralization of Acid Mine Drainage and Polluted Waters
	C. Sewage Plant Treatment

problem. For instance, chloride, and other solubles accumulate in the scrubber loop and must be purged⁽⁷⁻³⁰⁾. The Wellman-Lord process generates a sizable purge stream of mixed salts⁽⁷⁻³¹⁾. The best solution to these problems may be to immobilize the solubles in a stabilized sludge-ash mixture, thus attaining zero discharge and ending up with all the pollutants in a single inert mass⁽⁷⁻³⁰⁾.

Summary: Net Environmental Effects

Thus far, the success of FGD sludge disposal has depended largely on plant location. In areas where abundant suitable land adjacent to the plant is readily available, assuming proper environmental controls are adhered to, disposal by ponding appears to be an adequate solution. On the other hand, where available land is in short supply, the sludge disposal problem remains unresolved. In addition, the high cost of transporting sludge usually prohibits the use of disposal sites away from the plant.

If the sludge disposal site is not available for future land use, the land will lose its future productive capacity. Thus, additional sludge treatment by chemical fixation and alternative disposal processes through commercial utilization are being developed. However, chemical fixation can significantly increase the cost of sludge disposal, and few utilization options are economically feasible.

It appears that lime or limestone scrubber leachate could be a potential environmental problem. It is reported that leachates from scrubber sludges have a total dissolved solids content of 1000 to 2000 mg/l, a possible chemical oxygen demand, a toxic impact with sulfite ranging from 0.1 to 20 mg/l, and a possible trace element contamination. However, it has been demonstrated that a high adsorptive soil used as a liner could provide significant protection from groundwater contamination. The potential for surface contamination from accidental overflows will, nevertheless, likely remain.

The problems of air pollution from FGD wastes do not seem to have been reported. However, one can assume that air pollution would be less than that from the more solid, dry waste deposits from coal preparation plants. Furthermore, noise pollution is not found to be a problem with FGD systems.

Naturally Occurring Low-Sulfur Coal

The United States has a known reserve base of 384 billion tons of coal, most of which is not located near the major centers of energy demand (see Figure 29). The western region embraces 39.3 billion tons or 76.3 percent of the total coals that comply naturally with the national sulfur oxide emission standard of 1.2 lb/million Btu⁽⁷⁻²²⁾. Most of these coals are subbituminous and capable of being extracted by surface mining techniques. In addition, nearly all western subbituminous coals contain less than 2.0 percent sulfur, and in most the sulfur level is below 0.5 percent⁽⁷⁻³³⁾. These coals, however, are usually low in heat content and high in moisture and ash.

A switch to western coals would necessitate larger fire boxes for new power plants because of the high moisture and ash content of these coals. Moreover, at both new and existing plants, larger electrostatic precipitators for removing particulate matter and higher capacities for coal and ash handling facilities would be needed. The major cost, however, of utilizing low-sulfur western coal to meet SO_x emission limitations, would be the incremental cost of transporting coal to a distant utility⁽⁷⁻²²⁾.

The following discussion briefly describes the potential pollutants and control methods for utilizing naturally occurring low-sulfur coal. Because the majority of low-sulfur coals are embedded in the western United States, discussion is limited to this region.

Environmental Impacts of Western Coal Usage

Because such a large fraction of the coal found in the western United States is contained in deposits which are close to the surface, nearly all of the coal mined in this area is produced by a surface mining technique called area stripping. Area stripping proceeds stepwise through topsoil and overburden removal, mining of the exposed seam, topsoil and overburden replacement, and reclamation (see Figure 30). Major facilities at a typical area mining operation include haulage roads, run-off water collection and treatment facilities, a crushing and sizing plant, and loading facilities⁽⁷⁻³⁴⁾.

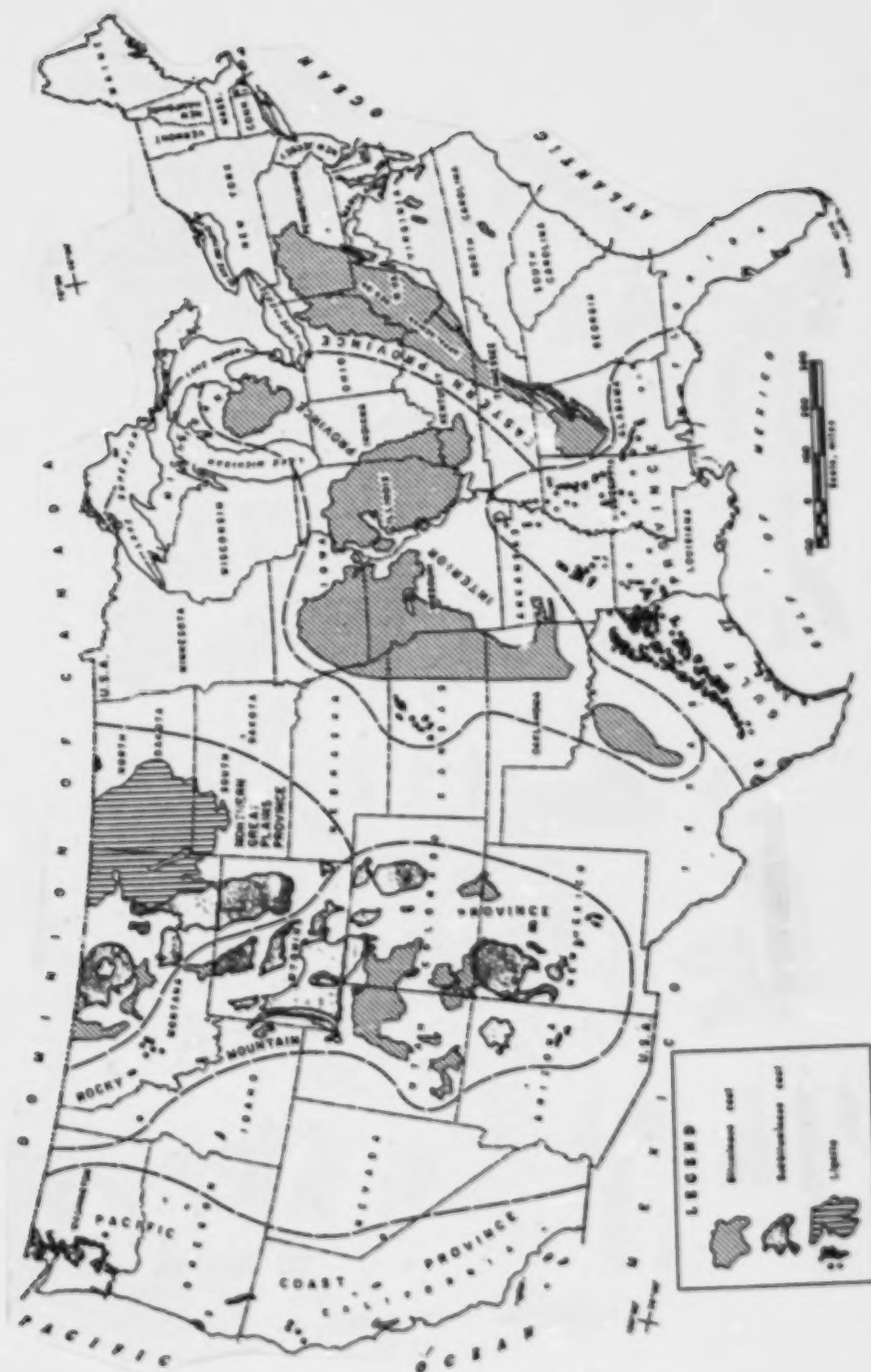


FIGURE 30. BITUMINOUS AND SUBBITUMINOUS COAL AND LIGNITE FIELDS OF THE CONTERMINOUS UNITED STATES (7-33)

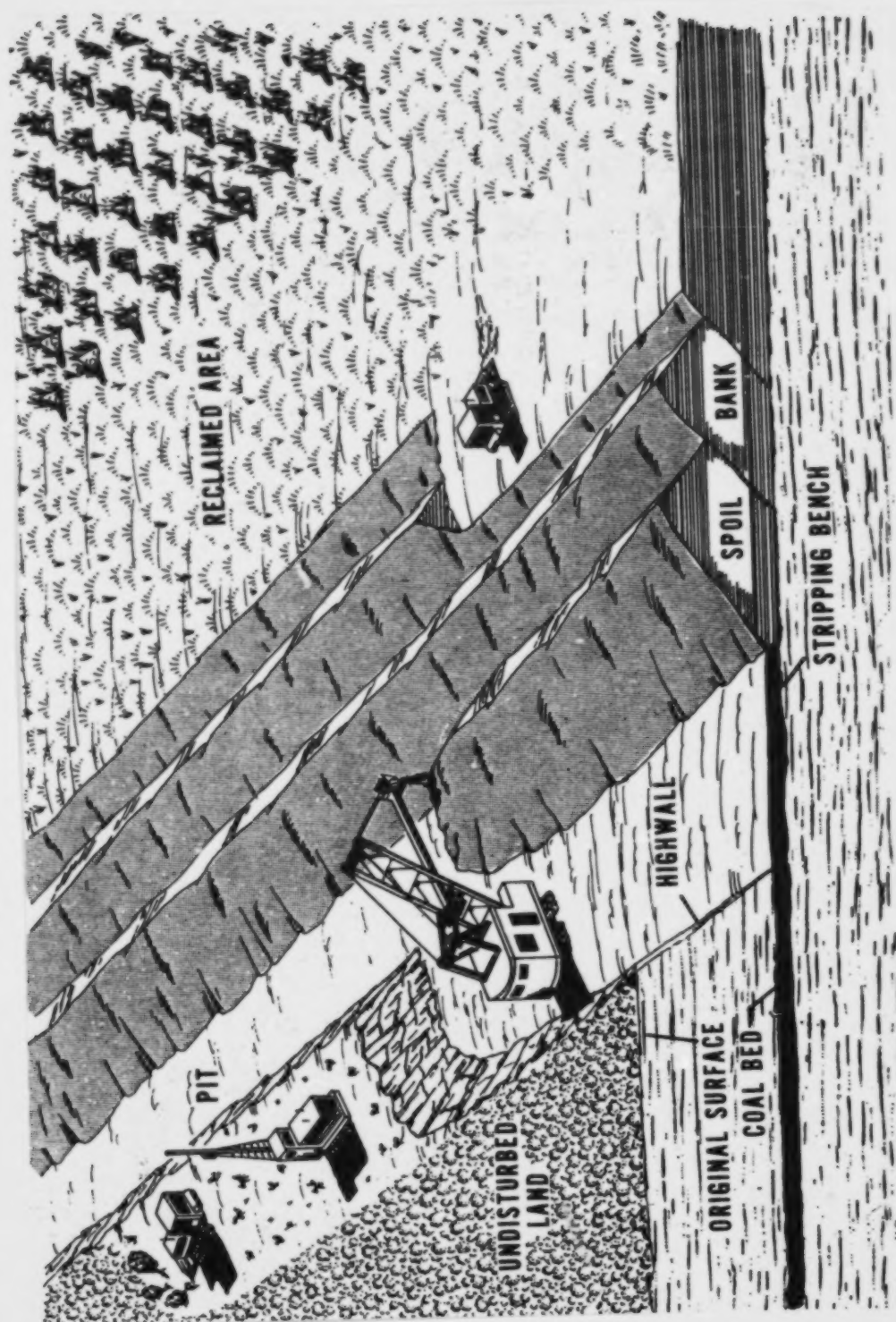


FIGURE 31. AREA STRIP MINING WITH CONCURRENT RECLAMATION (7-32)

The major sources of air emissions found within a typical area mining operation are particulate emissions from solids handling operations (topsoil and overburden removal, coal mining, hauling, storage, crushing, and loading operations) and gaseous emissions from diesel-powered mining equipment⁽⁷⁻³⁴⁾. The potential quantity of particulate and fugitive dust emissions when utilizing low-sulfur western coals may be slightly higher than those previously indicated for coal cleaning operations utilizing strictly bituminous coals. This is because western coals have lower heating values and higher total moisture and ash contents. This requires the handling and combustion of larger quantities of fuel to reach Btu output equivalent to bituminous coals. Nevertheless, methods for controlling these emissions would be the same as those described under coal cleaning. (See air pollution control for coal cleaning.) It should be pointed out, however, that in states such as North Dakota and Montana temperatures may fall to -40 or -50 F in the winter months, thus eliminating the possibility of using water-based dust suppression systems during this period⁽⁷⁻³⁵⁾.

Area mining activities may disrupt groundwater flow patterns and interrupt traditional sources of water supply. Water is in short supply throughout much of the western coal area, and the demands upon the existing supply are great. Both in the Northern Great Plains and the Southwest, the principal consumptive use of water in mining operations is dust control on access and haul roads; however, these activities do not present serious problems of aquifer depletion or competition with existing uses⁽⁷⁻³⁶⁾. But, area mining often disrupts natural drainage networks and causes internal or closed drainage between spoil banks and in mine sumps. Such interference with the natural drainage, however, ordinarily results from an increase in on-site consumptive use of water and may be only temporary⁽⁷⁻³⁶⁾.

The removal of overburden by area mining methods often exposes pyritic materials and increases the potential for the formation of acid drainage. The amount and rate of acid formation, and the quality of water discharged, are a function of the amount and type of pyrite in the overburden and coal, time of exposure, characteristics of the overburden, and the amount of available water⁽⁷⁻³²⁾. However, it should be pointed out that the annual precipitation in western coal fields is generally so low that the chances of significant drainage of water through waste materials are remote⁽⁷⁻²⁾. Where acid drainage

does occur, it can be controlled by backfilling and reclamation, preferably concurrently with the mining (see Figure 31).

In 1961, Zubovic et al. (7-37), conducted a geochemical study of trace elements in coal from the Northern Great Plains Coal Province. Table 36 shows the average trace element contents as determined by that study. It is not expected that trace element contamination would be a problem during most area mining activities, except perhaps during the preparation activities. The quantity and extent of potential contaminants would depend on the preparation method employed.

TABLE 36. AVERAGE TRACE ELEMENT CONTENTS FOR
COALS FROM THE NORTHERN GREAT PLAINS
REGION(7-37)

Element	Average ^(a,b)
B	116.0
Be	1.5
Co	2.7
Cr	7.0
Cu	15.0
Ga	5.5
Ge	1.6
La	9.5
Mo	1.7
Ni	7.2
Sn	0.9
Ti	591.0
V	16.0
Y	13.0
Zn	59.0

(a) ppm.

(b) 51 samples from Montana, North Dakota,
and Wyoming.

Finally, area mining often drastically alters the ecological characteristics of the area disturbed. The plant and animal communities in the arid West represent a successful evolutionary attempt by species to accommodate themselves to harsh sites. Large scale disruption of the habitats of endangered species may lead to their eventual extinction with the irreparable loss of genetic diversity⁽⁷⁻³⁶⁾.

Environmental Control

Generally, land disturbed by area mining can be rehabilitated. Rehabilitation implies that the land will be returned to a stable ecological state that does not contribute substantially to environmental deterioration and is consistent with surrounding aesthetic values⁽⁷⁻³⁶⁾. Moreover, a study of the rehabilitation practices at seven surface coal mines in the Northern Great Plains Coal Province revealed that the rehabilitated areas were more productive than comparable undisturbed areas⁽⁷⁻³⁸⁾.

Machinery and technology are now available for reshaping the physical environment to a wide variety of conditions. Surface configuration methods include terracing, pitting, ditching, listering, deep chiseling, and discing⁽⁷⁻³⁶⁾. Once these practices have been implemented, revegetation can begin. Revegetation practices include the use of mulched fertilizers, spoil treatments, cover crops, and mowing or grazing. The primary function is to stabilize the soil to prevent erosion and the formation of acid mine drainage. Secondary land usage is considered, but not in lieu of stabilization⁽⁷⁻³²⁾. If revegetation cannot be completed immediately, artificial stabilization with applied chemicals or with mulches is recommended until proper seeding can be done.

Rehabilitating disturbed areas for animal habitats is of great importance. It should be a primary consideration in designing and reshaping the spoil material and in selecting plant species to meet habitat requirements. In addition, the shaping of spoils to manage the water is an important aspect of rehabilitation. Surface flow may be impounded to provide water for animals, fish populations, or recreational uses, or it might be diverted entirely from the mine drainage⁽⁷⁻³⁶⁾.

Not only must the physical environment be cared for, but the human environment as well. Transportation facilities and adequate living quarters are scarce or absent in many of the new mining areas. Such developments have illustrated a need during premining activities for careful and extensive manpower and community planning, with training and recruitment programs geared to the staffing of new operations. Companies can no longer limit their concern to the growth that results from the employment of a given number of miners; they must concern themselves with the total impact resulting from growth and expansion⁽⁷⁻³⁹⁾.

Summary: Net Environmental Effects

The coal lands of the western United States are quite different from others in the nation. In the West, large low-sulfur coal beds, up to 50 feet thick, lie near the surface. Most of these coals can be extracted by area mining techniques. It is impossible to guarantee that pollution from area mining activities can be completely eliminated. However, it is realistic to expect that pollution can be greatly reduced.

Although technology is currently available for rehabilitating most of the land that has been area mined in the United States, little of it has yet been properly applied. Generally, the potential for rehabilitation is site-specific, and premining planning plays an important role. Certain land areas will be unsuitable for area mining where rehabilitation is not physically or economically possible, and where the proposed area is of critical environmental concern.

Techniques have been and are being developed by which mining and rehabilitation are integrated into a single operation. For instance, by the development and implementation of erosion and sediment control plans before, during, and after mining, erosion can be minimized. Moreover, acid mining drainage can be controlled by proper mining and rehabilitation techniques including overburden segregation, the burying of toxic materials, and the reapplication of top soil.

Environmental control for the preparation, handling, and transportation of western coals is generally the same as that discussed under coal cleaning.

Furthermore, depending on the level of preparation, contamination from trace elements could present a problem. Noise pollution is not considered to be a problem in area mining activities.

Environmental Trade-Offs of the Sulfur Removal Strategies

The process of assessing the environmental trade-offs of the sulfur control strategies is complicated because the strategies cannot be viewed as alternatives to one another. This is because the strategies as herein defined do not represent the complete system of supply and control. The low-sulfur coal strategy includes not only the mining function described but also transport, handling, storage, pulverizing, etc. In the same manner, the FGD strategy must be evaluated including the functions of mining, handling, storage, pulverizing, etc. Coal cleaning also has a number of associated functions not included in the discussion; the most important of these is mining. A further complication enters any evaluation such as this, also, when recognition is given to the fact that two or all three of these strategies may be used cooperatively, as considered in other parts of this report.

Another problem in properly identifying and delineating the environmental impacts of alternative strategies seeking similar objectives is to measure, by monitoring and surveillance, the quantitative content and extent of pollution under each strategy⁽⁷⁻⁴⁰⁾. Such information, however, generally is not available. Nevertheless, from the discussion of the environmental impacts presented, a preliminary qualitative summary can be presented of the environmental impacts of each of the nonalternative strategies.

Air Pollution

Air pollution from coal cleaning relates primarily to particulate emissions from the preparation plant, handling and storage facilities, and thermal dryers. In addition, gaseous emissions can occur from thermal drying and burning waste piles*. Several types of control devices are available

* Burning waste piles are not specifically associated with coal preparation plants. They may be associated with the disposal of any coal wastes, e.g., from mining and pulverizing.

to prevent and contain these emissions. However, frequently the disposal of waste particulates collected by an air emission device can involve additional problems.

The major types of air emissions found within a typical area mining operation are particulate emissions from solids handling operations and gaseous emissions from diesel-powered mining equipment. The potential quantity of particulate emissions, however, may be slightly higher when utilizing low-sulfur coals in comparison with the quantity from physical coal cleaning. This can be attributed to the handling and combustion of larger quantities of low-sulfur coals to reach an equivalent Btu output of bituminous coals.

Air pollution is not a problem with FGD systems.

Water Pollution

Water pollution from coal cleaning may result from process water production and acid drainage. These problems are controllable by a number of clarification and treatment techniques. However, improper disposal of the solid waste following water clarification and treatment may result in acid water drainage or accidental overflows at settling ponds.

Leachate from FGD sludge deposits may create an environmental problem. However, it has been demonstrated that a highly absorptive soil used as a liner could provide significant protection from groundwater contamination. Moreover, as in the case of coal cleaning, there is the potential for surface contamination from accidental overflows.

Water pollution from area mining operations may result in surface water contamination and acid drainage. Of particular importance are the off-site hydrologic impacts. However, the annual precipitation in western coal fields, where most area mining takes place, is generally so low that the chances of significant rainfall and drainage through waste materials are remote.

Although water pollution is a problem under these sulfur removal strategies, using available proper controls, it can be managed.

Solid Waste Pollution

Solid waste is the largest single source of potential pollution from coal preparation plants. Unsatisfactory disposal of these wastes can result in acid drainage and emissions from the spontaneous combustion of the refuse. Moreover, the coal refuse may contribute to the unsightly blight of the landscape and the destruction of local vegetation and wildlife. Although control measures are available to minimize these effects, the potential for pollution will remain.

The disposal problems with FGD sludges are not too different from those involved in the disposal of solid waste from coal cleaning. However, the thixotropic (quicksand-like) nature of the sludge makes it much more difficult to handle. Disposal of the sludges by ponding appears to be an adequate solution, assuming abundant suitable land is available and proper environmental controls are used. The land area to be used for this purpose, however, will be sizable.

Solid waste generation and total land impact appear to be greatest for area mining operations. For a typical operation, the land acres affected are several times more than from FGD or coal cleaning. Moreover, the waste produced from an area mining operation is generally twice the level of that produced from FGD or coal cleaning⁽⁷⁻²⁵⁾. However, proper rehabilitation practices can usually integrate these waste materials back into the natural environment at most sites.

Noise Pollution

Noise pollution should not be much of a problem under any of the three strategies. The potential for noise pollution is the greatest under the coal cleaning strategy; however, a number of control measures are available.

Trace Element Contamination

The fate of trace elements under the sulfur removal strategies has received limited attention and is not well defined. One would expect the

area mining of low-sulfur western coals to yield different concentrations of trace elements; however, methods for the control of these elements would be similar to those used for the coal cleaning and FGD strategies.

Summary of Impacts

Sulfur control strategies are in themselves trade-offs. But potential pollution problems are only being transferred from one medium of the environment to another. The rationale for this transfer is based on the assumption that contamination from sludge or solid waste in remote disposal areas is easier to control or alleviate than the more ubiquitous forms that are discharged by the burning of coal. On the other hand, environmental trade-offs between the strategies are not as easy to detect. The low-sulfur strategy seems to have the greatest potential for air pollution and solid waste generation. In addition, the total land impact appears to be the highest under this strategy even though large areas will be needed for the disposal of FGD sludge. The potential for water pollution and trace element contamination seem to be of equal concern to all three strategies, while the potential for noise pollution appears to be the greatest under coal cleaning. These impacts have been described for typical environmental conditions and assumed use of proper environmental controls. Nevertheless, given site-specific conditions (i.e., land use, micro-climate, soils, vegetation) and various levels of environmental controls, the relative environmental impacts may change.

In the ultimate, another type of evaluation may be more enlightening. This would be a comparison of the overall fuel supply, sulfur control, and waste disposal system with and without certain subsystems used or included. For illustration, such a comparison has been made to evaluate the effects of coal cleaning on the overall environmental impacts of the total system in which deep-mined high-sulfur coal is cleaned prior to scrubbing. Unfortunately, because of a dearth of quantitative data, the comparison is only qualitative. But, the qualitative comparison in Table 37 does provide some guidance in the environmental evaluation of the effect of coal cleaning impacts.

The major environmental impact of coal cleaning as a pollution control technique for boilers, both utility and industrial, can perhaps be summarized

TABLE 37. DEGREE OF CHANGE IN POLLUTANT EMISSIONS
RESULTING FROM ADDITION OF COAL
CLEANING TO THE ENERGY PROCESS

	Emission of Air Pollutants		Emission of Water Pollutants	Solid Waste
	SO ₂	Others		
Coal Cleaning	+	+	+	++
Coal Storage		-	-	
Coal Combustion	--	--	-	
Combustion Wastes:				
Ash			-	-
FGD Sludge			-	-
Total	--	--	-	--

-- Significant decrease.
- Some decrease.
++ Significant increase.
+ Some increase.

as the concentration of the removal of sulfur and other pollutants from coal at a few hundred coal preparation plants rather than from the flue gases from many thousands of boilers. This is, of course, at the cost of incurring some environmental impacts at the coal preparation plants; but, on balance, the environmental impacts (and social and dollar costs) are judged to be reduced via this route. The degree of change applies to all coals, all coal cleaning processes, and all sizes and types of boilers. The net result, as shown in Table 37, is significant decreases in air pollutants and solid waste quantities, and some decrease in water pollutant generation. Although this table does not provide a complete picture for all possible system variations, it does show the significant environmental advantages resulting from the application of coal cleaning in combination with FGD. Attempts to quantify these effects and to study other system variations should be made even though other system variations are believed not to result in such large environmental benefits.

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SECTION 8

BARRIERS

A number of barriers exist which may impede the continued development and deployment of physical coal cleaning as a sulfur dioxide control technique. These barriers fall into several categories: technical, environmental, transportation, institutional, economic and social, and legislative and regulatory. The nature of the constraints in each of these categories is discussed briefly in this section. Further detail regarding these barriers is presented in Appendix G.

Technical Barriers

Technical barriers to the widespread implementation of physical coal cleaning as a sulfur control technique can be classified into three major areas:

- The lack of techniques for accurate prediction of the cleanability of raw coals
- The lack of techniques for quality control in the cleaning process to assure a product of consistent sulfur content
- The lack of techniques for effective liberation and rejection of fine-size pyrite.

Prediction of Coal Cleanability

Accurate prediction of the sulfur and ash content of a cleaned coal product is essential as a basis for making an investment decision to develop a coal resource and to build a coal cleaning plant. Laboratory float-sink separations have been performed on a limited number of coal samples to provide the basic data required for the prediction of coal cleaning results. Generally

these tests are done at three stages of crushing and at three specific gravities. Although the available data are valuable, they are limited in number and in scope. Float-sink analysis has been performed principally on coal samples from existing mines. This work needs to be extended to undeveloped coal reserves. Also, these data generally do not include top sizes below 14 M. Similar studies at finer coal sizes are needed to determine the maximum cleaning potential.

In addition to these limitations in existing cleanability data, there is difficulty in extrapolating laboratory test results to the performance of a full-sized plant.

A computer model, Coal Preparation Simulation Model-Version 4 (CPSM4), has been developed to simulate the operation of a coal cleaning plant. However, performance characteristics of various types of coal cleaning equipment need to be studied over a broader range of operational variables. This type of investigation is needed to provide improved data, which can be used in simulation models to predict the effectiveness of a commercial plant. Finally, the computer model must be validated further by comparison of predicted performance with that actually achieved by commercial plants.

Quality Control

The value of cleaned coal product to the utility or industrial buyer will depend not only on the level of sulfur content achieved by cleaning, but also on the consistency of the product quality. Although cleaned coal has more uniform properties than raw coal, the continuous variations in feed coal characteristics make it difficult to achieve the degree of uniformity desired. Analytical methods for continuous monitoring of sulfur, ash, and moisture content have been developed. These need to be perfected and methods for automatically adjusting process parameters in response to changes in the product need to be developed. An alternative scheme for quality control would be to use automatic blending techniques to minimize sulfur variation in the cleaned coal product.

Separation of Fine-Size Pyrite

Coal washability data indicate that, in general, finer grinding results in greater sulfur rejection and higher yield. However, current separation techniques are impractical for handling very fine coal. In addition, no data are available on which to base calculations using theoretical models to predict the desulfurization potential of fine coals by floatation or other fine coal cleaning techniques. Improved techniques need to be developed for the separation of fine pyrite in order to take advantage of the greater sulfur rejection potential.

Environmental Barriers

The environmental impacts of physical coal cleaning are discussed in Section 7. The major areas covered are: air and water pollution, solid waste, noise, and trace elements. Environmental control of problems in each of these areas is technically feasible, so that these environmental factors are not, in themselves, barriers to the use of coal cleaning. However, there are related barriers, namely:

- Uncertainty concerning the level of control which is desirable, or which may be required, for each of the potential pollutants.
- The cost of control technology.

Both factors have a direct bearing on the decision to invest in a coal cleaning plant. The level of pollution control required for the coal cleaning plant will determine the cost of control which, in turn, impacts the cost of the cleaned coal product. The cost of the product determines its competitive position and the potential profitability of the investment in the coal cleaning plant. Another factor in the competitive position is the perception of the increased value of the cleaned coal by the user because of the benefits that will accrue to him through its use.

Uncertainty concerning pollution control requirements is a particularly serious barrier. A coal cleaning plant designed with appropriate environmental control processes and procedures to meet existing regulations could show favorable economics, and yet, a decision to build the plant might be deferred for fear that new regulations in the future, say with respect to trace element control, would require a sufficiently large investment in control hardware that the venture would turn unprofitable.

The costs associated with state-of-the-art pollution control equipment and procedures for coal cleaning facilities are tabulated in Section 7. These costs must, of course, be included in the economic evaluation of coal cleaning processes.

Transportation Barriers

The problems anticipated in the movement of cleaned coal to users are basically the same as those faced by the coal industry in general. These are:

- The need to upgrade and replace badly deteriorated track and roadbed in some rail systems
- The need to expand rail line capacity generally, and at selected locations to avoid blockage points
- The need for new branch and access rail lines to serve new mine development
- The need to expand waterway transportation systems to avoid localized overload points
- The need to solve disputes over slurry pipeline construction.

Transportation of cleaned coal does introduce some variations in these patterns. These include the following considerations:

- More Btu's of cleaned coal can be carried per rail car or barge. This reduces the cost, and also has the effect of increasing the transport system capacity.
- The reserves of cleanable coals are even more localized than coal generally. This could exacerbate the problems of blockage or system overload points.
- The possible use of coal cleaning plants in combination with slurry pipelines may improve the overall economics.

The first point is obviously beneficial to all parties. The reduced transportation cost aids both seller and buyer, and the increased capacity effect could be important to rail systems facing situations of limited capacity.

On the other hand, a greatly increased utilization of coal cleaning would result in disproportionate increases in production from coal reserves which have favorable cleaning properties. Depending on the exact locations of these reserves, this could add to problems of localized capacity limitations.

Site specific evaluations of such situations would be required to determine where problems of this type might occur.

Another problem associated with the localized occurrence of cleanable coals is that economical transportation routes to all potential users may not be available. Thus, the management of a utility plant might decide that it would be beneficial to burn cleaned coal, but they may find that coals from their conventional suppliers are not readily cleanable. Further, they may find that the nearest source of cleanable coal is far enough away that the increased transportation distance offsets the lower transport cost per Btu. Even so, the use of the cleaned coal may still prove to be a net economic advantage because of other benefits which accrue to the plant through the use of cleaned coal. Again, the analysis must be done on a site-specific basis to obtain a definitive result.

Water use and the energy required to remove process water are important factors in both coal cleaning and in slurry pipeline transport. The fact that cleaned coal is produced initially in slurry form raises the possibility that the use of a slurry pipeline to transport the product could have improved overall economics. One drying step would be eliminated and the total water requirement would be less than for the two processes considered separately.

More detailed discussions of supply/demand relationships, transportation requirements and economics, and slurry pipeline considerations are given in Appendix G.

Institutional, Economic and Social, and Legislative and Regulatory Barriers

Numerous factors, covering the broad range of institutional, economic and social, and legislative and regulatory considerations, were evaluated as potential barriers to widespread adoption of coal cleaning as an SO₂ emission control technique. On the basis of this analysis, the following factors were found to inhibit the growth of coal cleaning.

- PCC's wide range of possible benefits and costs in different applications are not well appreciated--by electric utilities, coal companies, and current or would-be industrial coal consumers.

- In general, electric utilities and their respective public utility commissions have particularly poor knowledge of developments in PCC technologies and their possible applications.
- Existing engineering/economic studies of PCC are believed to provide a wholly inadequate basis for investment decision making. Such studies would be seen as improved if data from actual full-scale PCC demonstrations were included, and if PCC economics were shown as sensitive to such things as the price of coal, its pyritic content, transport costs, boiler performance, boiler or contract lives, different SO₂ standards, and the type of investor.
- Relative small coal companies, which may control significant quantities of cleanable reserves, may be unable or unwilling to bring these coals into the marketplace unless they have assistance in establishing institutional arrangements which enable them to share in the use of PCC plants.
- Although the EPA Administrator has given credit towards the percentage removal requirements in NSSPS revisions, PCC, unlike FGD, is not yet considered a pollution control investment by the IRS; hence, PCC is put on unequal footing vis-à-vis FGD with respect to certain tax and financing advantages.
- Existing supply contracts under a limited number of circumstances could prove a constraint to PCC investment; however, if coal companies invested in PCC, price adjustment clauses could provide a vehicle by which to spread the costs of coal cleaning for sulfur removal purposes.
- Uncertainties are perceived as to the ultimate costs of air and water quality standards applied to PCC plants.
- Enormous uncertainty is perceived by investors in several related areas of EPA activities: enforcement of SIP's, enforceability of SIP's, appropriate averaging periods, the viability of continued noncompliance, variance policies, quadrennial reviews of standards, redefinitions of Best Available Control Technology (BACT) and BACT applications, offset policies, rate at which standards may become more stringent, and the ultimate stringency of standards for SO₂ from coal-fired boilers.

Summary discussions of these factors are presented in this Section. Expanded treatment of these subjects, and of those factors analyzed but not found to be significant barriers, are given in Appendix G.

Lack of Appreciation of PCC Benefits

The majority of potential PCC investors contacted in the course of this study expressed surprise that PCC should be considered a sulfur removal strategy for boilers subject to anticipated New Source Performance Standards (NSPS) revisions. Even those who were aware that Section 111 (a) (1) of the 1977 amendments to the Clean Air Act granted the EPA Administrator authority to permit credit toward the percentage removal requirement for precombustion cleaning were skeptical that PCC in combination with FGD would prove a least-cost compliance option.

Findings on the extent to which potential investors appreciate PCC benefits for NSPS and SIP standards applications indicate a somewhat better appreciation for PCC benefits than is the case for revised NSPS applications. Even where FGD/PCC combinations might be applicable, there is somewhat greater knowledge of the beneficial role PCC might play. Hence, it appears that the percentage removal requirement associated with NSPS revisions is what has inhibited investigation of PCC for that case.

Although it is difficult to generalize on what potential investors know or perceive as PCC benefits in combination with FGD and what potential benefits they are unaware of, it can be said that the following PCC benefits are reasonably well appreciated:

- Reduced effective transportation costs
- Reduced ash disposal costs, both capital investment and operating cost savings
- Possibility of reduced FGD capacity; hence, reduced investment in FGD
- Reduced FGD operating and maintenance costs, including lime/limestone requirements
- Reduced pulverizing costs.

Other benefits which have been associated with the combination of PCC and FGD appear to be less appreciated. These include:

- Reduced variability in the sulfur content of coals; hence, possible scaling down of FGD design capacity as needed to take variability into account
- Reduced likelihood of need for FGD reheat
- Increased FGD reliability
- Possible increased probability that boilers may continue to operate in the event of an FGD malfunction or in the event of an energy emergency
- Reduced boiler maintenance costs, since PCC produces less corrosive coal and coal with more uniform characteristics
- Reduced particulate control costs
- Ability to use very high sulfur and, thus, relatively cheap coals in boilers subject to NSPS revisions
- Enhanced economic prospects in those areas where very high sulfur coals are mined.

Despite these advantages--some certainly more fully appreciated than others--there has not been a tremendous rush to invest in PCC for sulfur removal purposes. Greater development and dissemination of information concerning PCC benefits would certainly appear to be in order.

Inadequate Implementation

It is not surprising to find that a significant factor in the lack of widespread enthusiasm for PCC as a sulfur removal strategy lies in the fact that it has not been implemented widely on a commercial scale. Estimated engineering cost data, largely deduced from information on coal cleaning for ash removal, are not accurate enough for investment decisions.

Sound and relevant "investment decision-grade" data are not available for the five potential markets for which PCC may be a suitable control strategy. These markets are:

- Electric utility boilers subject to SIP's
- Large boilers subject to NSSPS
- Electric utility boilers subject to NSSPS
- Industrial boilers subject to SIP's
- Industrial boilers subject to NSSPS.

Data for a broad cross-section of possible PCC applications would require experimentation with PCC in combination with FGD, blending, and a variety of types of coals.

Position of Small Coal Producers

Currently, about 15 percent of the nation's coal is produced in about 80 percent of the nation's mines. Generally, coal produced at these mines (about 4,000 of them) is sold without any preparation. It is shipped at single-car rates, which means it costs \$2 to \$3 more a ton to ship this coal than it does to ship coal produced in the same area from large mines. Coal produced at large mines, if it is going to large volume markets, is shipped at unit-train rates.

In order for firms to take advantage of unit-train rates, several conditions must be met. The most important of these are high volume movement between a single source and a single market and a means by which to load unit-trains quickly and efficiently. A coal transloader is necessary to perform this task. A transloader may involve a capital investment of about 7 million to 12 million dollars, with an annual operating expense of about 1 million dollars. Small coal producers are not in a position to afford such investments. Their production is too low to make it economically attractive. Also, the cost of preparation plants, often located adjacent to transloading facilities, is of this same order of magnitude, also not generally feasible for small producers.

Given this situation, it should be noted that a significant fraction of cleanable reserves may now be controlled by small producers, especially those in Central Appalachia. How might these resources be tapped? Three arrangements should be possible: contract preparation, cooperative preparation, and consolidation.

First, it may be possible for small producers to have their coal cleaned at the PCC plants of large firms. One such arrangement has been working for ten years in Appalachia, Virginia, where a preparation/transloading operation is set up to serve two utilities in North Carolina. General Coal Company (Westmoreland) financed and operates the facility. The facility is built at the site of a Westmoreland mine which accounts for 1.6 million tons

(40 percent) of the facility's 4 million ton yearly throughput. Another 35 percent comes from smaller Westmoreland mines, some of which are operated by independent contractors, located within 25 miles of the facility. Fully 25 percent of the coal comes from the mines of small independent coal producers in the area.

Without access to this facility, it is doubtful that the production from the small independent mines would have a market. In the future, if PCC plants are to be built principally for sulfur removal along with ash removal purposes, relationships such as this may flourish. But problems exist. For example, the coals which would be washed at such facilities must have similar heat, ash, and sulfur contents to make the arrangement work. Further, and very importantly, the small independent producers must feel they would be getting fair treatment when participating in such an arrangement. As matters now stand, because in many cases such producers may have no market without coal preparation (and access to transloaders and unit-train rates), there is nothing to discourage large coal companies from extracting a rather high price for the service they may provide the small producer. Presumably antitrust provisions might provide a measure of economic protection in this regard; still, the perceptions small producers may develop for such arrangements may lead them to seek alternatives.

The second arrangement would be for small producers to form cooperatives for the purpose of financing and operating facilities for coal cleaning and loading. Cooperative relationships permit small firms to pool their resources in an equitable manner and to take advantage of certain tax provisions and financing mechanisms. For a variety of reasons, however, co-ops take painstaking effort to establish and even greater effort to maintain.

The basic problems with co-op formation and maintenance have to do with reliability, trust, and the need to place the interests of the collective ahead of the interests of the individual members in the event that these interests diverge. Small coal producers have a reputation, deserved or not, for being independent-minded--some call it unreliable. Such producers may be very uncomfortable with such things as production quotas. Yet co-ops are established so that if one member fails to make a fair contribution, all other members will suffer.

Another barrier to the successful formation of coal co-ops involves the fact that purchasers of coal may not believe these relationships will last.

If so, they may not wish to commit themselves to long-term contracts for co-op coal. The purpose of co-op formation with respect to PCC facilities is, of course, to get in a position to land a long-term contract. Without such a contract, large new capital investments--e.g., in PCC, transloader, or railroad rolling stock--would certainly seem imprudent and would very likely not be feasible.

A final possible means by which the cleanable reserves of small coal companies could be brought into the marketplace would be through the business consolidation of small firms. With the impact of surface mine reclamation and mine health and safety legislation having a strong effect on the prospects for small firms in particular, there is reason to believe consolidations will take place, if bankruptcies do not occur first.

Tax Status of Coal Cleaning Investments

One factor which may inhibit the adoption of PCC as a sulfur emission control strategy is that, unlike FGD systems, coal cleaning does not now qualify for tax purposes as a pollution control investment. This determination has been made by the Internal Revenue Service, and the effect of this ruling on the part of the IRS is to put PCC on an unequal (that is, more expensive) footing vis-à-vis scrubbers.

The IRS ruling is based on the agency's belief that PCC investments are made principally for purposes of gaining a commercial advantage over firms that do not clean the coal they sell. The fact that substances which might pollute are removed in the cleaning process would be seen as incidental to the so-called essential purpose of the investment--to repeat, to gain commercial advantage.

A section in the 1977 amendments to the Clean Air Act may suggest that the IRS could be urged to reconsider this ruling. Section 111 (a) (1) gives the EPA Administrator authority to permit "credit" toward the percentage removal requirement in NSPS revisions for precombustion cleaning of coal.*

There are many precombustion coal cleaning processes, and perhaps at some time one of these, or a combination of them, may clean the coal to the

* The new NSSPS (June 11, 1979) reflect credit for sulfur removal by coal cleaning; thus, the IRS may, in the near future, change its viewpoint.

extent required under NSSPS, at a calculable cost. For the time being, however, it appears that precombustion cleaning must be combined with FGD to achieve, say, an 80 or 90 percent sulfur removal. Since "credit" may be given for both types of sulfur removal, this would appear to offer prima facie evidence that precombustion cleaning (e.g., PCC) is placed on an equal footing with postcombustion cleaning as a pollution control strategy.

If PCC were granted status as a pollution control investment, three financial/economic benefits would be made available for such investment:

- Accelerated depreciation, that is, over 5 years, could be taken for tax purposes (presently, a PCC plant can be depreciated only over its anticipated useful life).
- A 5 percent investment tax credit may be taken (prior to 1977, pollution control investments qualified for either accelerated depreciation or a 10 percent tax credit, not both).
- Tax-exempt pollution control revenue bonds (PCRB's) may be used to finance the investment (but because tax-exempts now flood the narrow tax-exempt market, and since PCRB's are unsecured debt, use of PCRB's by firms whose financial positions are not robust may be of marginal benefit).

Existing Contracts

When some of the situations in which PCC may emerge as a desirable SO₂ control option are specified, and then the relevant provisions of typical utility coal contracts are analyzed in that context, it appears that there are relatively few instances in which the terms of the contracts themselves would strongly deter investments in coal cleaning.

At least four types of conditions may occur which would suggest adoption of PCC by a utility or industrial coal burner at an existing installation:

- Revision of State Implementation Plan (SIP) SO₂ emission standards, or tighter enforcement of existing SIP's, such that cleaned coal must be burned in order to meet the revised standards (Case 1).

- Recognition by the utility or industry that cost and/or technology changes have made physical coal cleaning clearly an economically attractive pollution control technique (Case 2).
- Promulgation of new regulations limiting the sulfur content of coals sold in selected regions (Case 3).
- Ruling to prevent economic disruption or unemployment (Case 4).

As a result of any of these scenarios, either singly or in concert, existing contractual arrangements between coal companies and users might be a critical factor in determining the users' response.

For any of these cases, most parties would attempt to renegotiate their contract in order to avoid termination. In such event, PCC is one option of many and probably could be implemented by the parties if it was clearly the least costly alternative. The same outcome results in the case of terminated contracts. In two limited circumstances, however, existing contractual obligations might bar its implementation.

- If the coal contract contained a take-or-pay provision, if the coal company used that as leverage to refuse consideration of PCC, and if the utility did not breach its agreement.
- If the coal contract contained an early termination provision, if the coal company refused to consider PCC, and if the utility valued a continued relationship with a reliable supplier more than implementation of a slightly less expensive pollution control technology.

Neither combination of circumstances is likely to occur frequently.

In the event of cost and/or technology changes very favorable to PCC, contracts could be renegotiated to provide for PCC. In cases where the coal company was unable to supply cleaned coal, however, most utilities would probably not abrogate existing agreements, and the contract might then serve as an obstacle to adoption of PCC. Still, if PCC became increasingly widespread, it is unlikely that a substantial number of coal companies would refuse to consider it for existing contract customers.

Pollution Standards for Coal Cleaning Plants

The impact of pollution control requirements on the cost of coal cleaning plants, and hence, on the related investment decisions was discussed in a preceding section on environmental barriers. In the final analysis this becomes a regulatory barrier which can be eliminated only by promulgation of firm and final pollution standards for coal cleaning plants at the earliest possible date. Only then can investment decisions be made without being clouded by concern over possible future changes in the requirements for control.

Uncertainty Regarding SO₂ Standards

The major factor which inhibits efforts to do anything about evaluating SO₂ control strategies is the lack of enforcement of SIP standards. Although many firms' plants are on compliance schedules, many are not. As a result, noncompliance has become for many firms the most reasonable, that is, least-cost solution to problems with SO₂ emissions.

That is not to suggest that firms will necessarily go out of their way to avoid investment in coals or processes which might enable boiler operations to be in compliance with standards. To consciously and purposefully seek to avoid compliance--without, for example, bothering to plead for variances--could lead to legal action.

In the course of the survey of would-be investors in PCC as an SO₂ emissions control strategy, one crucial barrier was mentioned by virtually all investors contacted; that is, that planning to invest in control strategies is greatly complicated by the fact that the targets keep changing. Further, few venture to make estimates of where the standards are going, how fast they are likely to move, and where they are likely to end up. (Some suggested facetiously that they would end up at zero emissions.)

The obvious problem this suggests is that an investment in PCC, for instance, could become obsolete overnight with either a more stringent standard or a redefinition of the Best Available Control Technology (BACT) and/or a redefinition of where the old or new BACT should be applied.

SECTION 9

NECESSARY ACTIONS

To recapitulate, this study has developed extensive information on how much coal in the United States is clean (low in sulfur content); on how much coal can be cleaned by physical techniques; on the status of the available technology; on what the costs of physical coal cleaning are likely to be; on environmental impacts (with and without coal cleaning); and on the barriers that are preventing the nationwide full-scale implementation of coal cleaning as a sulfur oxide control method.

A careful analysis of all the information gathered leads to the conclusions that physical coal cleaning is the least-cost method of reducing SO₂ emissions from the combustion of coal and that accelerated deployment of the technology should be promoted. Unfortunately, however, despite all the advantages of coal cleaning, it is neither widely accepted nor widely used. In fact, although about 40 percent of all coal mined in the United States is cleaned in some fashion, most industrial organizations and the majority of the utilities--as explained in Section 8--have not shown an interest in its use as a sulfur oxide control method.

Section 9 holds two basic premises--first, that widespread use of physical coal cleaning (PCC) would benefit the entire nation, and, second, that action by the Federal government is the only way to remove the barriers blocking PCC's use. The primary agencies which need to work together in exercising their powers in order to promote coal cleaning are the U.S. Environmental Protection Agency itself, the Internal Revenue Service, the Interstate Commerce Commission, the Department of Energy, and Congress.

Two Types of Policy Approaches

As the central Federal agency with an interest in promoting coal cleaning for SO₂ control, EPA should encourage the establishment of an overall PCC

policy to guide short- and long-term planning and action by the Federal government. With a national coal cleaning policy, the government will be in a better position to take the initiative in accelerating PCC. One of the following approaches could be adopted..

- (1) Encourage growth in coal cleaning by assuring not only that PCC is competitive in the marketplace*, but also that coal users believe that it is worth investing in.
- (2) Establish policies to require that all coal be cleaned before it is burned.

Preliminary Research and Development
Necessary Under Either Policy

Regardless of the approach EPA selects, a set of technology-related initiatives also must be undertaken to make coal cleaning a more efficient technique in SO₂ emission control. Although coal cleaning has been employed for years for ash removal and Btu enhancement, its use specifically to remove sulfur is new. Adequate ash removal technology exists, but coal cleaning with the purpose of sulfur compound removal, although feasible, is still an art which must be advanced by applying and improving the present technology to establish proven plant designs for sulfur removal. Much development must take place to establish the technique on a firm technical basis. The nonuniform nature of coal underlies the major technical problems to be overcome. As coal characteristics differ, their separation properties differ, and the optimum approach to cleaning changes. In the technical area, the Federal government (EPA and/or DOE) should initiate at least nine research and development programs, outlined in Table 38.

This extensive, though not exhaustive, listing of research and development requirements demonstrates that an intensive effort is required to bring coal cleaning for sulfur removal to the stage where the benefits of the technology can be fully realized. Nothing less than a dedicated effort with broad Federal support can achieve that goal.

* The new NSSPS (promulgated June 11, 1979) has been the first step in establishing this policy.

TABLE 38. NECESSARY COAL CLEANING RESEARCH AND DEVELOPMENT
AND ITS RATIONALE

Necessary Research and Development	Rationale
<u>1. Coal Washability Data</u> Ongoing experimental determinations directed at obtaining additional data on coal washability must be greatly accelerated and expanded. The washability data available now are extremely limited in comparison to the untested reserves. Massive quantities of data are required because results cannot be extrapolated from one seam to another. Correlational techniques should be further explored in an effort to minimize the experimental data needed for each seam. Until coal washability data for all mineable seams are available to the government, to the mining industry, to the electric utilities, to other coal users, and to other interested parties, decision makers in the private and public sectors cannot select the locations for new coal cleaning facilities to achieve maximum performance and lowest cost.	
<u>2. Equipment Performance Correlations</u> Correlations of performance for individual items of equipment are needed to permit optimum design and control of cleaning plants. Such correlations can be obtained only by analysis of experimental performance data recorded under a variety of conditions. Some experimental data still need to be obtained. Through prior knowledge of equipment performance under various operating conditions, plant designs may be guaranteed and operating set points properly selected. Such knowledge is important for investors, plant operators, coal users, and government regulators because only through efficient, effective, and progressive plant design and operation of coal cleaning plants can the economic viability of the coal cleaning strategy be ensured.	
<u>3. Plant Simulation Model</u> A comprehensive coal cleaning plant simulation model must be available to permit the optimization of plant designs and plant operations. The comprehensive model, when computerized, must be capable of processing inputs concerning a broad range of coal characteristics, the Through the use of the powerful tool of a plant simulation model, operating primarily on washability and equipment performance data, efficient, accurate, and optimum designs and control set points may be achieved quickly. Such a capability will enhance the acceptance of coal cleaning by decision makers in government and industry.	

TABLE 38. (Continued)

Necessary Research and Development	Rationale
range of cleaning techniques available, the performance of individual types of equipment when presented with different coals (as exemplified by their washability), and costs of various plant designs.	
<u>4. Advanced Separation Techniques</u>	
Development of advanced separation designed specifically for sulfur removal must be accelerated--including research on fine and ultrafine particle separation and on chemical cleaning techniques for organic sulfur removal. The goal of these developments must be maximum sulfur removal at a specified cost or minimum cost at a specified level of sulfur removal.	When improved separation techniques become available, the environmental and economic benefits of coal cleaning will be more apparent.
<u>5. Process Control System and Sensor Development</u>	
Systems for the control of cleaning plant product quality must be developed. Sensors detecting changes in feed coal characteristics and product coal quality should provide inputs to the control system, perhaps based on the computer simulation model, so that equipment control set points would be changed. These changes in set points would be designed to moderate product quality variations.	Product quality, e.g., sulfur level and ash content, is important to coal users so that they may maintain stable and efficient boiler operation while meeting sulfur emission standards. Such product quality cannot be obtained more easily if process control systems and sensors are developed. The alternative would be the selective mining, cleaning and blending of coals to ensure a consistent product. This is costly but process control systems would reduce these costs.

TABLE 38. (Continued)

Necessary Research and Development	Rationale
<u>6. Demonstration Plants</u>	
Commercial coal cleaning plants must be built to validate the advanced separation techniques as they become available. Analysis of the overall performance of these plants will provide much-needed engineering and cost data.	Only when full-scale coal cleaning plants have been built and operated successfully will all concerned parties be fully convinced of the total applicability of the coal cleaning strategy for sulfur removal. Only through continued demonstration will all doubts be removed.
<u>7. Variability of Sulfur in Coal</u>	
In the operation of demonstration and other plants, determination of the sulfur variability in product coal as compared with the feed coal must be required of the operators. Using these collected data, statistical studies must be performed so that intelligent selection can be made of sulfur levels of coal to be burned in relation to the emission levels permitted. Two candidate statistical approaches, traditional and geostatistics, giving contrasting results, are currently available for study.	For all concerned, including coal users, government regulators, environmentalists, and the public, it is important that sulfur variability be understood. If too much control is achieved, the cost will be too high; if not enough control is possible, ambient sulfur levels may be too high and human health and the ecology may suffer.
<u>8. Boiler Performance Data</u>	
Existing data must be collected and additional experimental data must be generated on the effects of cleaned coal combustion on boiler performance. Only through the analysis of such data may the potential benefits accruing from the burning of cleaned coal on boiler availability, maintenance, capacity, efficiency, etc., be evaluated.	Knowledge and proof of these additional benefits from the burning of cleaned coal on boiler performance would provide even more evidence to users and would aid in convincing them to adopt this control strategy. Additional economic benefits to clean coal users can be projected today on the basis of scattered data showing improved boiler operability.
<u>9. Environmental Control</u>	
Demonstrations of acceptable practices for solid waste disposal and for the control of pollutants in water effluents are needed.	Coal cleaning will not be a viable antipollution strategy unless the wastes produced by its application can be controlled. Although the

TABLE 38. (Continued)

Necessary Research and Development	Rationale
Few data are available on trace metals migration and control and on infiltration of pollutants into groundwater. The development of acceptable practices and their demonstration in conjunction with plant demonstrations should be accomplished.	problems involved are not overly difficult to solve, their solution must be demonstrated if coal cleaning is to be acceptable as an antipollution strategy.

Beyond the technical barriers and the initiatives required to overcome them, there remain other obstacles to widespread use of coal cleaning. These tend to differ somewhat depending upon the basic policy approach selected. Therefore, they will be discussed within that framework.

Policy to Assure
Competitiveness of Coal Cleaning

Rationale

Assuming a successful outcome of the technical initiatives just outlined, the private sector (coal companies and utilities) will make investment decisions on the basis of "bottom-line" economics. In general, the institutional, legislative, and regulatory barriers identified in Section 8 are barriers because they have an impact on the economics of coal cleaning. Therefore, a policy to assure competitiveness by removing these barriers and provide incentives would result in rapid deployment of the technology.

Initiatives Designed to
Implement the Policy

Possible actions which could influence coal companies and utilities to invest in coal cleaning include the following:

- (1) Promote Regulation Stability. Federal and state EPA's could remove the uncertainties regarding both SO₂ emission regulations and environmental regulations pertaining to coal cleaning plants. The private sector could then make investment decisions based on known costs of compliance without fear that future changes would cause the investment to become unprofitable.
- (2) Provide EPCA Loan Guarantees. The Federal government could provide loan guarantees under Section 102 of the Energy Policy and Conservation Act (EPCA) for building centralized coal cleaning facilities to be used for processing the output of many small coal producers.
- (3) Appropriate Plant Construction Funds and Permit Management-Fee Plant Operation. Congress could appropriate funds to construct coal cleaning plants to be operated by industry on a management-fee basis in a manner similar to that used by the Reconstruction Finance Corporation in the building of synthetic rubber plants during World War II. Provision could be made for the private sector to buy the plants once profitable commercial operation is demonstrated.
- (4) Reduce Tax or Subsidize. Congress could legislate provisions for a lower income tax rate or for direct subsidies based on the percent of sulfur removed prior to the sale of the coal.
- (5) Permit Pollution Control Investments for Tax Purposes. The Internal Revenue Service--through Congressional intervention if necessary--could reverse their position so that coal cleaning plants would qualify as pollution control investments for tax purposes. Arguments for revision can be based on EPA's move to credit precombustion sulfur removal toward an SO₂ percentage removal standard.
- (6) Allow Unit Train Rates for Rail Shipment. ICC regulations could be changed to allow rail shipment of cleaned coal at the same rates as uncleaned coal.

- (7) Establish Public Information Program. EPA should create a task force to establish a top-notch public information program to educate utilities and potential industrial users about the benefits of burning cleaned coal.

Policy to Require Coal Cleaning

Rationale

A policy to require that all coal be cleaned before combustion has merit on several grounds.

- Low Cost. Physical coal cleaning is the least-cost method for reducing SO₂ emissions.
- Quick Results (No Retrofitting). Cleaned coal could be used immediately in all existing facilities. There are essentially no "retrofit" problems. Thus, decreased SO₂ emissions can be achieved as soon as cleaned coal becomes available. In contrast, the NSPS for coal-fired boilers will not materially affect total SO₂ emissions until a significant fraction of existing boilers are retired and replaced.
- Significantly Reduced SO₂ Emissions. State-of-the-art (ash removal) cleaning methods could reduce uncontrolled emissions of SO₂ from coal-burning facilities by an estimated 32 percent if all coal were cleaned. Even greater reductions would be anticipated as economically feasible advanced processes capable of removing organic sulfur are developed. Scrubbers, operating at 85 percent sulfur-removal efficiency, would have to be installed on 38 percent of the entire coal-burning capacity to achieve an equivalent reduction in SO₂ emissions.
tion in SO₂ emissions.
- Extended Boiler Life, Etc. The use of cleaned coal is expected to extend boiler life, improve efficiency, and increase the capacity factor--all significant conservation, operation, and cost benefits.

Initiatives Designed to
Implement the Policy

Congressional action probably would be necessary to mandate nationwide coal cleaning. The technology-related research and development programs listed previously must be accelerated so that the improvements needed soon become fully available and demonstrated. Finally, measures designed to assure that capital is available for construction of coal cleaning plants will be required, as explained in Section 2. These could include loan guarantees or the "Rubber Reserve" type of government involvement as listed under the first policy option; accelerated depreciation allowances; product price supports; or other measures.

SECTION 10

POTENTIAL FOR APPLICATION OF COAL CLEANING TECHNOLOGY

Five important conclusions grow out of the analyses described in earlier sections of this report:

- Significant quantities of U.S. coal can be cleaned to meet various SO₂ emission limits.
- Several reasonable incentives can be adopted to increase the use of coal cleaning.
- There are numerous economic incentives for using coal cleaning.
- The combustion of clean coal results in many operational benefits.
- Although there are formidable barriers to the widespread adoption of coal cleaning, these barriers can be eliminated.

These conclusions tend to confirm that coal cleaning is potentially highly important--alone and/or in combination with flue gas desulfurization--in meeting the energy demands of the nation in an environmentally acceptable manner.

However, at least three important interrelated questions remain to be answered.

Question 1. Can it be shown that coal cleaning is an important factor in SO₂ emission control, both regionally and nationally, and, if so, over what period of time can clean coal be produced to meet various possible emission limits?

Question 2. In what manner and to what extent, both emissions-wise and time-wise, can coal cleaning be utilized to reduce SO₂ emissions in the United States?

Question 3. How will the costs of clean coal affect its demand in comparison with the demand for other competitive SO₂ emission control techniques?

This section outlines an approach to the development of information required to answer these three questions and presents the results obtained from this final analysis.

Approach

To arrive at answers to Question 1 about the potential of coal cleaning, researchers analyzed not only the possibilities available in the United States as a whole but also six specific regions within it.

The final analysis required four steps:

- To determine the coal demand of existing industrial and electric utility facilities
- To determine the SIP requirements for each facility
- To aggregate the demand of all the facilities in each state operating under specified SIP limits
- For each SIP, to compare the demands for coal of the required quality with the quantities that could be made available by coal cleaning.

The details of the first three steps of the analysis are presented in Appendix E. The cleaned coal quantities required in the fourth step were obtained from the Reserves Processing Assessment Model (RPAM).

The RPAM model was run first with raw coal as the supply, then successively with coal cleaned by one of eight processes, including the three examples defined below as the supply. The eight coal cleaning processes are defined in Appendix E. The first three, used as examples in this section, are as follows.

- A. Physical coal cleaning using 1-1/2-inch M coal separated at 1.6 s.g.
- B. Physical coal cleaning using 3/8-inch M coal separated at 1.6 s.g. if this produced coal to meet the standard; otherwise, 1.3 s.g. was used for separation. An operating penalty of 1 percent energy loss was assumed.

C. Meyers process: for raw coal with greater than 0.2 percent pyritic sulfur, the level of pyritic sulfur is reduced to 0.2 percent. No sulfur reduction takes place if the raw coal pyritic sulfur level is less than 0.2 percent. A 5 percent energy loss was assumed plus an operating penalty of 2 percent energy loss and a weight loss of 10 percent.

As a means of answering Question 2, a further analysis of the computer model results was performed. A description of the approach is inherent to the presentation of the results given subsequently.

The evaluation of Question 3 requires a complex analysis. Therefore, plans were made and carried out to use the Utility Simulation Model developed by Teknekron⁽¹⁰⁻¹⁾. This model was designed to evaluate economic trade-offs among various SO₂ emission control strategies.

Results

The details of the procedures followed and indications of the numerical results obtained are presented in Appendix E. Only summary examples of the results obtained are presented here, showing answers to the three questions outlined at the beginning of this section.

Availability of Cleaned Coal to Meet SO₂ Emission Regulations

The value of coal cleaning in increasing supplies of coal for compliance with strict SO₂ regulations may be seen in Figure 32, which is a visual representation of some of the results for the Northeast. The results are shown in the form of bar charts. In each chart the ratio of total coal to annual demand (or years of availability) is plotted against annual demand. The width of each bar represents the aggregate demand of all facilities in the region that operate under SIP's in the range shown at the top of the bar, while the height of the bar represents the number of years that compliance coal would be available if used at the current rates. The area of each bar represents the total quantity, in 10¹⁵ Btu, of coal in the reserves of the Northern Appalachian Region that can satisfy the SIP's in the indicated range. The horizontal dotted line shows the years of coal availability, at the current

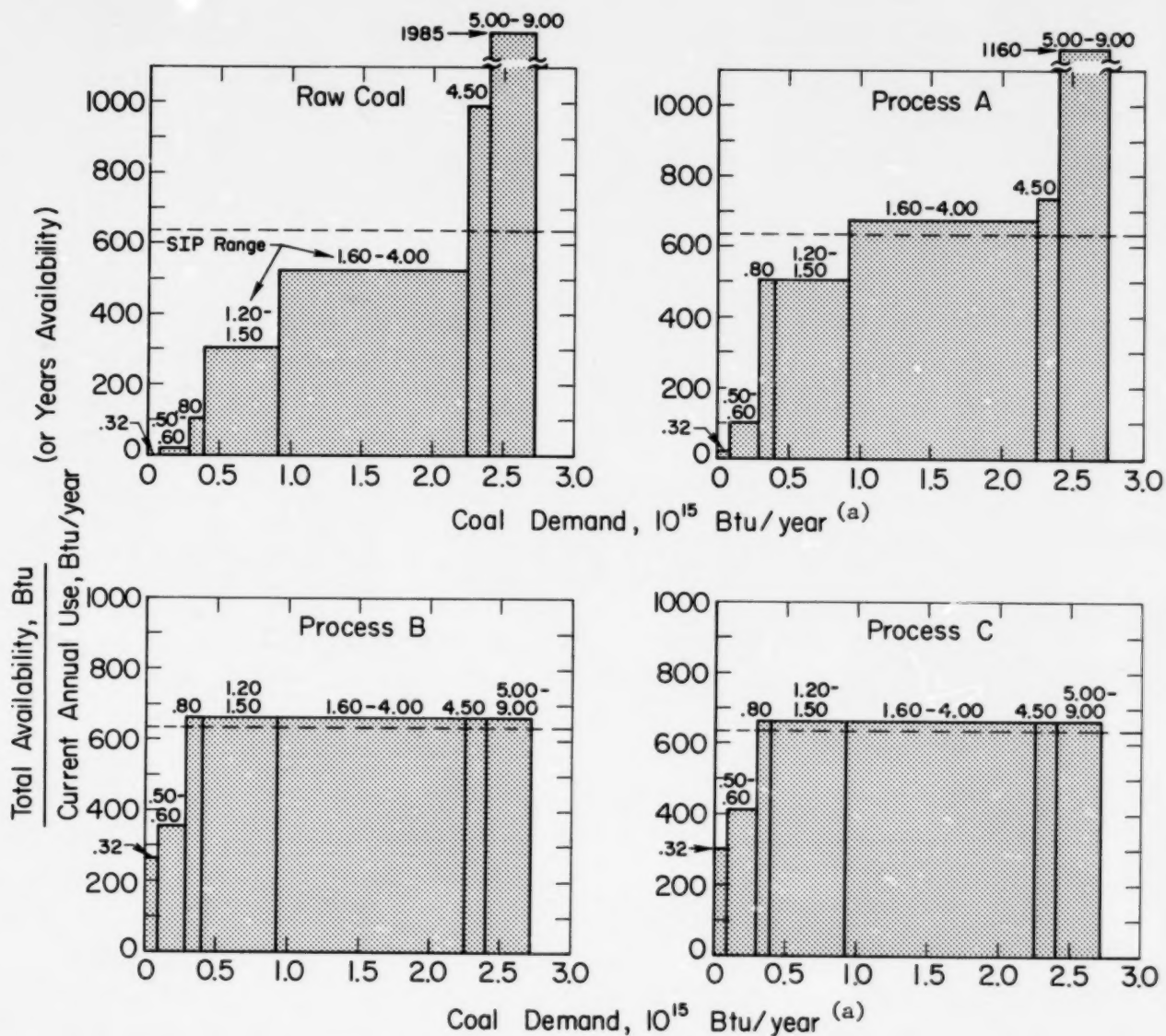


FIGURE 32. INCREASE IN THE QUANTITIES OF SIP-COMPLIANCE COAL ACHIEVABLE BY COAL CLEANING--NORTHEASTERN U.S. (see text for definition of processes)

(a) Northeast U.S. utility and industrial coal demand met by coal produced in the Northern Appalachian region.

rates of use, if used without regard to sulfur content, and the area under the dotted line represents the total Btu's of coal in the reserves of the Northern Appalachian Region.

The four bar charts show the results for raw coal and for coal produced by the three example cleaning processes as just defined. The charts show clearly the usefulness of these coal cleaning processes in producing coal to satisfy SIP's. The chart for raw coal shows that very little coal in the region could be burned in compliance with a SIP of 0.32 (New Jersey, industrial, metropolitan areas), and that only limited quantities of raw coal are sufficiently low in sulfur content for SIP's of 0.5 to 0.8 to be met. On the other hand, the charts for coal cleaned by Processes A, B, and C show progressively increasing quantities (increases in the shaded areas) of coal in compliance with low SIP's that can be produced by these cleaning processes.

Similar bar charts are shown in Figure 33 for the Western Midwest Region. The ability of coal cleaning to increase supplies of coal to meet strict SIP's is equally apparent in this series of charts.

The ability of coal cleaning to increase supplies of coal to meet SIP's, of course, is reflected as well in the results for the entire U.S., Table 40. In this case, the full increase in supply for the most restrictive SIP's is not discernible because, for even the simplest cleaning process, the increase in supply is large enough that other groups of users with less restrictive SIP's but with greater demand ultimately draw from the same coal as that supplying the most restrictive SIP's.

Although Table 39 shows very large increases in the amount of compliance coal that can be achieved through coal cleaning, the complete results in Appendix E show that for some regions, particularly Southeastern United States and Alabama and neighboring states, coal cleaning apparently does not change the supply of compliance coal markedly. There are two reasons for this. The first is that, because large users under high (less restrictive) SIP's end up using coal of lower sulfur content than required, the increase in supply of coal with reduced sulfur content produced by cleaning cannot be detected by the model as designed. If the large users under high SIP's were to acquire coal of quality just sufficient to meet their SIP's from the northern Appalachian producing region, an increased supply of coal with reduced sulfur content produced by coal cleaning would become noticeable. The second reason is that coal cleaning, although still a useful process

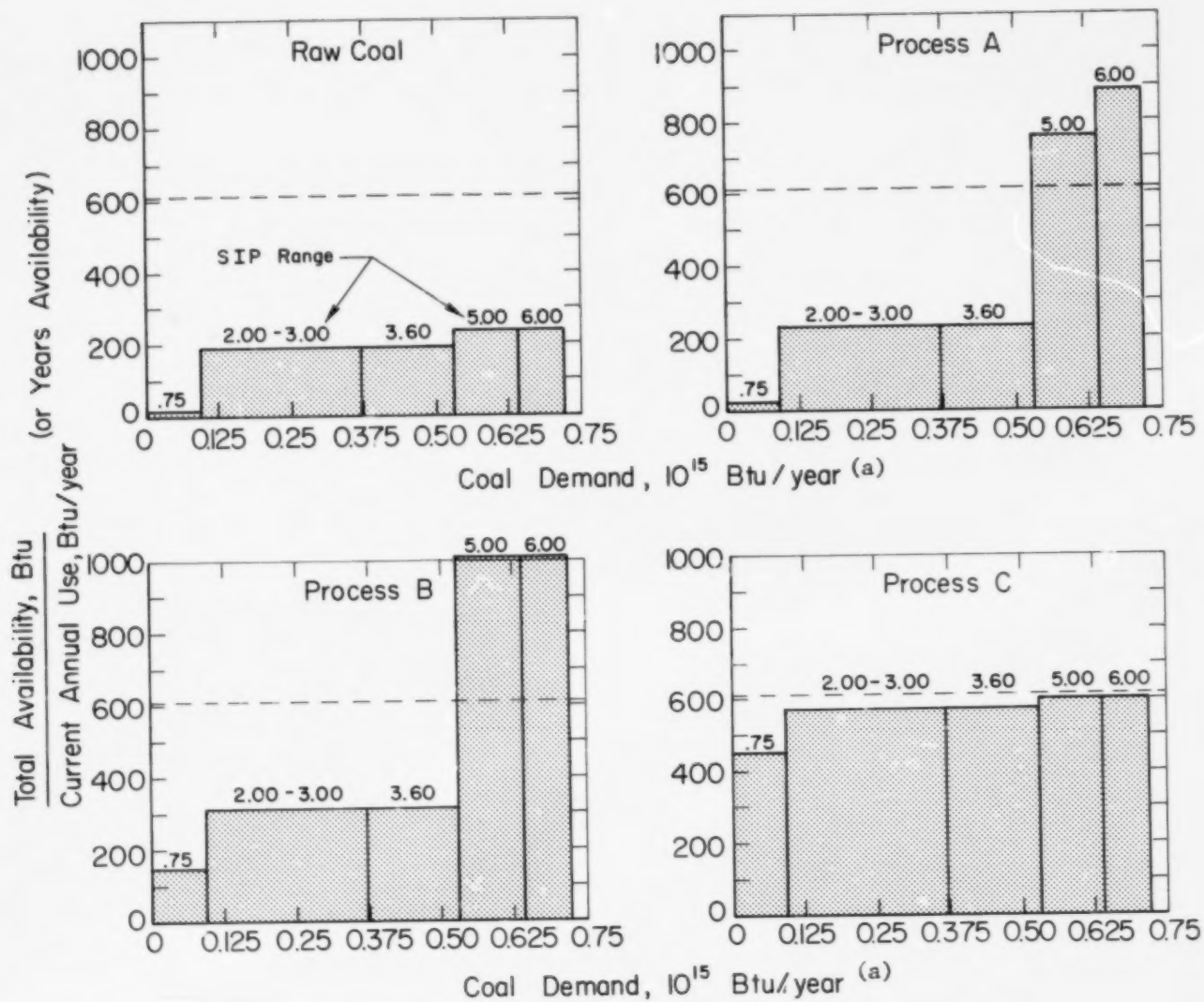


FIGURE 33. INCREASE IN THE QUANTITIES OF SIP-COMPLIANCE COAL ACHIEVABLE BY COAL CLEANING--WESTERN MIDWEST U.S.

(a) Western Midwest regional utility and industrial coal demand met by coal produced in the same region.

TABLE 39. INFLUENCE FOR THE ENTIRE CONTIGUOUS UNITED STATES OF COAL
CLEANING ON SUPPLY OF COAL TO MEET EXISTING INDUSTRIAL
AND UTILITY DEMANDS

SIP Range lb SO ₂ / 10 ⁶ Btu	Aggregate Coal Capacity, 10 ⁹ Btu/hr	Annual Coal Demand (a)			[Total Availability, Btu] ÷ [Current Annual Use, Btu/yr], (or Years of Availability)		
		10 ⁶ tons	10 ¹⁵ Btu	Raw	Cleaning Process (b)		
					A	B	C
0.20	1.07	0.13	0.004	140	887	934	940
0.22	16.77	3.64	0.08	442	887	934	940
0.25-0.33	56.64	11.82	0.26	762	887	934	940
0.50-4.00	1,575.68	325.91	7.17	771	887	934	940
4.50-5.00	162.99	34.09	0.75	771	991	934	940
5.20-6.00	174.57	36.82	0.81	779	991	934	940
6.17	12.98	2.73	0.06	1,389	991	934	940
7.00-*(c)	57.10	11.36	0.25	6,952	2,187	1,141	940
Total	2,057.82	426.55	9.384				

(a) Capacity converted to demand assuming 3,854 hours of operation per year (load factor = 0.44) for industrial combustors, and 4,818 hours/year (capacity factor = 0.55) for utility boilers.

(b) See text for definition of cleaning processes.

(c) * No limit on SO₂ emissions.

for coals produced in these two regions, is not as effective in reducing the sulfur content of these coals as it is for coals of other regions. This is apparent from the data of Tables 8 and 9 in Section 3 of this report.

As important as cleaned coal is to meeting SIP's, it must be noted that, because some of the SIP limits are $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$ or lower, the results of this analysis show that coal cleaning also can be useful in meeting the 1971 NSPS. Furthermore, the technology has a role in satisfying the revised NSSPS for utility boilers. The RPAM results given in Section 3 show that, for significant portions of the reserve, cleaning of the coal prior to combustion materially reduces the efficiency requirement on a scrubber system to achieve a combined sulfur removal of 90 percent.

Thus, to answer Question 1, coal cleaning is an important factor which has broad applicability regionally and nationally with regard to meeting the various SO_2 emission standards. The results indicate that, even without using Western Region coal, about 200 years of compliance with SIP limits can be achieved.

Impact of Coal Cleaning on SO_2 Emissions

The contribution of existing coal-fired facilities to nationwide SO_2 emissions will continue well into the future. The NSPS of 1971 and the recently promulgated revision, NSSPS, will prevent large increases in the total SO_2 emissions from burning coal by placing strict controls on new plants, but emissions from plants not covered by these regulations will decline only slowly as old plants are retired. Plants built prior to 1971 are regulated under SIP's; hence, reduction in SO_2 emissions from existing facilities could be accomplished by making the SIP's more restrictive.

The information and results obtained in this analysis can be used to estimate the reduction in SO_2 emissions that could be achieved by lowering certain SIP emission limits. The SO_2 emissions from existing facilities, if current SIP's are met, can be calculated from the information in the tables of Appendix E. For each facility group the annual coal use, obtained by multiplying the total capacity by the assumed hours of operation per year, is multiplied by the SO_2 emission limit to obtain the total annual SO_2 emissions for that group. These totals can be assumed for all groups within a region to obtain the total SO_2 emissions for a region. If one assumes that a maximum

SIP were set for a region, with lower SIP's unchanged, the resulting SO₂ emissions can be calculated as before. The quantities of coal in the reserve to meet the revised SIP can be obtained from the Reserves Processing Assessment Model output.

The results of two such calculations can be summarized as follows.

Region 1. Northeastern United States

- SO₂ emissions under existing SIP's = $6,600 \times 10^6$ lb SO₂/yr
- Under a maximum SIP of 1.5, lower SIP's unchanged:
 New SO₂ emissions = $3,600 \times 10^6$ lb SO₂/yr (or a reduction of 45 percent from current SIP's).

Coal Reserves in Region 1 to Meet SIP of 1.5

<u>Coal</u>	<u>10⁶ tons</u>	<u>10¹⁵ Btu</u>	<u>Years at</u>
			<u>2.72 x 10¹⁵ Btu/hr</u>
Raw	8,100	179	65
Cleaned Process A	15,600	344	126
Cleaned Process B	28,200	620(517)	227
Cleaned Process C	28,300	623(579)	229

Thus, placing a maximum SIP of 1.5 lb SO₂/10⁶ Btu on the facilities in Region 1 would reduce SO₂ emissions by an estimated 45 percent. Raw coal in the region would last only 65 years under the reduced SIP; however, coal cleaning by Process A would increase the supply to 126 years while coal cleaning by Process B or C would extend the supply to nearly 230 years.

Region 4. Eastern Midwest

- SO₂ emissions under existing SIP's = $7,500 \times 10^6$ lb SO₂/yr
- Under a maximum SIP of 1.8, lower SIP's unchanged:
 new SO₂ emissions = $4,300 \times 10^6$ lb SO₂/yr (or a reduction of 43 percent from current SIP's).

Coal Reserves in Region 4 to Meet SIP of 1.8

<u>Coal</u>	<u>10⁶ tons</u>	<u>10¹⁵ Btu</u>	<u>Years at</u>
			<u>3.03 x 10¹⁵ Btu/yr</u>
Raw	3,300	73	24
Cleaned Process A	6,600	145	48
Cleaned Process B	9,400	207	68
Cleaned Process C	10,900	240	79

Thus, in Region 4, SIP's lowered to 1.8 lb SO₂/10⁶ Btu would result in an estimated 43 percent reduction in SO₂ emissions. Coal cleaning could double or triple the coal supply to meet this reduced SIP.

Thus, to answer Question 2, through the use of physical coal cleaning alone (and judging from the example results), about 43 percent of the SO₂ emissions from the SIP-regulated facilities could be eliminated for periods ranging from 63 to 227 years, without the use of Western Region coal.

Effect of Costs on Projected Demand for Cleaned Coal

Because cleaned coal can be used to meet SO₂ standards and because the use of cleaned coal has a number of advantages to the user, the technology is attractive as an SO₂ control method. The extent to which it is applied will be determined by the comparative costs of alternative methods of control.

An analysis of projected demand for cleaned coal was conducted by a subcontractor using a utility simulation model⁽¹⁰⁻¹⁾.

The actual coal cleaning costs plus the cost of coal lost in cleaning ranges from one to ten dollars per ton, as developed in Section 5. In some cases, the benefits of coal cleaning, when fully accounted for, will be more than sufficient to cover these costs and the net cost of coal cleaning will be zero or even negative. In other cases the benefits will not cover the coal cleaning costs and the resultant net cost of cleaned coal must be

compared with the cost of alternative methods of control. Each user must make this analysis himself, because the outcome will depend upon a number of site-specific factors that include the cleanability of coal in the region, the type, size, and load factor of the facility, and the nature of the SO₂ emission regulation which must be met.

In answer to Question 3, it is difficult to find any logic against the universal application of coal cleaning on an economic basis. Thus, there appears to be no economic limit to the extent of application of coal cleaning as an SO₂ emission control technique.

Conclusions

The results reported in this section indicate that coal cleaning has high potential as a means of SO₂ control, nationwide and long term. Cleaned coal can be used to comply with standards established by the State Implementation Plans, and it is in this role that coal cleaning can have the greatest impact. The quantities of cleaned coal that can be provided to meet SIP's is in most cases many times the quantities of uncleaned compliance coal in the reserve, and the reserves of cleanable coal are large enough that current SIP's could be met, at least until the year 2100 at current demand.

Coal cleaning also would permit, as shown by example, the lowering of SIP's without penalty in many situations and could be used in many regions for meeting the 1971 NSPS of 1.2 lb SO₂/10⁶ Btu without the supplemental use of flue gas desulfurization. Coal cleaning alone would not be sufficient to meet the current NSSPS.

From the users' standpoint, coal cleaning has several important advantages as a method for SO₂ emissions control:

- No facilities modifications are required. The use of cleaned coal is, in effect, an instantaneous retrofit.
- No capital is required by the user.
- Solid waste disposal requirements are reduced over the use of uncleaned coal, and, in the case of combined coal cleaning and FGD, solid waste production is reduced over the use of FGD alone.
- Increased boiler capacity and availability, reduced boiler maintenance, and other benefits are expected from the use of cleaned coal as outlined in Section 6.
- Total costs for the generation of steam or electricity will be lower when cleaned coal is used.

In summary, it cannot be overemphasized that coal cleaning can be used with excellent results to meet certain SO₂ emission regulations. When all its costs and benefits are fully accounted for, coal cleaning will be more than competitive with alternative methods of control such as flue gas desulfurization.

As previously mentioned, the actual market penetration of the technology, of course, will depend not only upon communication of the benefits of cleaned coal to potential users but also upon removal of barriers to the use of cleaned coal through the actions discussed in Section 9. Active programs in education and barrier removal could markedly strengthen the naturally high potential of coal cleaning technology as a strategy to reduce SO₂ emissions and improve air quality throughout the United States.

References for Section 10

- (10-1) Cukor, P., Fisher, K., et al., "An Evaluation of Physical Coal Cleaning as a Sulfur Dioxide Emissions Control Strategy in the Electric Utility Sector", submitted to Battelle's Columbus Laboratories under subcontract, April, 1978.

APPENDIX A

COAL DATA

APPENDIX A

COAL DATA

Coal Production and Coal Characteristics

Recent Coal Production

The levels of coal production for 1975 by state and county for the eastern and western regions of the United States are shown in Tables A-1 and A-2, respectively^{(A-1,A-2,A-3)*}. Average values of sulfur content, ash content, and calorific content of coals on both a county and state basis also are presented in Tables A-1 and A-2. The total coal production for the eastern states in 1975 was 537.5 million tons (short), with West Virginia, eastern Kentucky, Pennsylvania, Illinois, western Kentucky, and Ohio being the largest producers in that order. The total coal production for 1975 for the western states in 1975 amounted to 110.9 million tons. The largest producers were Wyoming, Montana, Texas, New Mexico, and Colorado in that order.

Sulfur Content of Coal

The 1975 production of bituminous and lignite coals by state versus sulfur content range for both the eastern and western regions of the United States is shown in Table A-3^(A-1,A-2,A-3,A-4).

The eastern region produced 153 million short tons of coal with less than 1 percent sulfur. This was 28 percent of the total eastern production. Most of this low-sulfur coal was produced in West Virginia, eastern Kentucky, and Virginia. Another 29 percent of eastern coal production contained sulfur

* References for Appendix A are listed on page 250.

TABLE A-1. PRODUCTION AND COAL CHARACTERISTICS DATA BY COUNTY
AND STATE - EASTERN REGION - 1975^(a,b)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
ALABAMA				
Bibb	285	0.8	7.3	13,700
Blount	853	0.8	6.5	13,260
Cherokee	11	-	-	-
Cullman	592	0.8	4.9	13,610
DeKalb	447	-	-	-
Fayette	747	0.7	10.2	12,740
Franklin	15	-	-	-
Jackson	774	1.3	10.2	13,370
Jefferson	7,664	1.3	7.7	13,770
Lamar	3	-	-	-
Marion	567	1.0	4.0	13,530
St. Clair	49	1.7	8.5	13,460
Shelby	576	0.5	4.8	14,140
Tuscaloosa	2,587	1.2	8.0	13,590
Walker	6,556	1.0	9.0	12,940
Winston	928	1.3	4.3	13,130
STATE TOTAL OR AVERAGE	22,654	1.0	7.7	13,410
GEORGIA				
Chatooga	W ^(a)	-	-	-
Dade	W	-	-	-
Walker	-	1.4	9.3	13,270
Undistributed	74	-	-	-
STATE TOTAL OR AVERAGE	74	1.4	9.3	13,270
ILLINOIS				
Christian	W	4.1	12.3	10,600
Douglas	2,540	2.0	7.6	11,560
Franklin	W	1.0	9.3	11,890
Fulton	2,638	3.3	11.0	10,790
Gallatin	W	3.6	10.8	12,590
Jackson	55	2.6	9.8	11,830
Jefferson	6011	1.3	9.3	11,800
Johnson	1	-	-	-
Knox	1334	3.6	9.8	10,730
Macoupin	W	4.3	11.1	10,650
Montgomery	W	3.9	10.6	10,660
Peoria	W	2.9	11.8	10,540
Perry	11,675	3.1	11.2	11,240
Randolph	8,209	3.7	12.5	10,980
St. Clair	W	3.8	12.4	11,030
Saline	2,025	2.3	8.9	12,370
Stark	270	3.7	11.9	10,390
Vermilion	15	2.5	10.4	10,930
Wabash	W	2.2	13.1	10,480
Williamson	3,364	1.8	10.0	11,940
Undistributed	21,399	-	-	-
STATE TOTAL OR AVERAGE	59,536	2.9	10.6	11,260
INDIANA				
Clay	1,102	2.7	8.1	11,500
Daviess	97	3.3	9.6	10,960
Dubois	W	2.0	8.6	11,200
Fountain	40	3.1	9.3	11,270
Greene	W	3.1	9.3	11,490
Knox	W	3.2	10.9	11,200
Owen	11	1.3	6.3	11,740
Parke	4	3.2	8.3	11,360
Perry	10	2.7	5.2	11,750
Pike	5,560	2.5	8.2	11,730
Spencer	347	5.2	8.8	11,600

TABLE A-1. (Continued)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
INDIANA (Con't)				
Sullivan	W	1.7	8.6	11,400
Vermillion	W	2.8	10.2	11,330
Vigo	34	2.1	11.0	11,020
Warrick	W	3.4	9.8	11,450
Undistributed	17,718	-	-	-
STATE TOTAL OR AVERAGE	25,123	2.6	9.0	11,510
KENTUCKY, EASTERN				
Bell	3,924	1.0	7.9	13,010
Boyd	76	2.5	15.4	10,660
Breathitt	6,531	1.2	9.5	13,280
Carter	263	1.3	8.9	11,820
Clay	1,171	1.1	6.3	13,420
Elliot	473	-	-	-
Floyd	4,462	0.8	5.5	13,440
Greenup	182	2.2	9.5	12,030
Harlan	10,860	0.8	5.8	13,660
Jackson	521	1.4	9.9	12,150
Johnson	1,513	1.0	5.2	12,960
Knott	4,198	1.0	8.9	12,660
Knox	1,781	1.1	7.2	13,290
Laurel	1,564	2.3	6.3	13,250
Lawrence	851	-	-	-
Lee	187	2.1	8.2	12,680
Leslie	3,595	0.9	8.5	13,830
Letcher	4,912	1.2	6.1	13,540
McCreary	836	2.6	9.2	12,970
Magoffin	1,701	1.1	7.8	12,860
Martin	6,872	0.8	9.0	12,900
Menifee	7	-	-	-
Morgan	1,107	-	-	-
Owsley	303	1.1	5.5	13,150
Perry	6,400	0.7	7.2	12,880
Pike	19,178	0.8	7.9	13,450
Pulaski	463	1.4	8.9	12,250
Rockcastle	74	0.5	7.7	12,250
Wayne	211	-	-	-
Whitley	2,858	0.9	5.7	13,140
Wolfe	182	-	-	-
Undistributed	-	-	-	-
STATE TOTAL OR AVERAGE	87,256	1.0	7.2	13,110
KENTUCKY, WESTERN				
Butler	731	1.3	5.2	12,310
Christian	199	2.2	5.8	12,220
Daviess	W	3.6	11.1	10,850
Edmonson	34	-	-	-
Grayson	40	-	-	-
Hancock	261	4.9	8.6	11,590
Henderson	W	2.7	9.9	11,120
Hopkins	9,813	3.7	9.8	12,190
McLean	856	3.0	9.5	11,700
Wuhlenberg	22,456	3.7	10.0	11,890
Ohio	10,079	3.4	8.9	12,030
Union	W	3.5	10.5	12,650
Warren	2	-	-	-
Webster	2,007	3.5	10.6	12,570
Undistributed	9,878	-	-	-
STATE TOTAL OR AVERAGE	56,356	3.6	9.9	12,140
MARYLAND				
Allegheny	952	1.1	8.3	13,820
Garrett	1,654	1.8	11.2	13,380
STATE TOTAL OR AVERAGE	2,606	1.3	9.3	13,680

TABLE A-1. (Continued)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
OHIO				
Athens	128	1.6	10.4	11,610
Belmont	15,282	3.5	10.7	12,500
Carroll	235	3.3	10.0	12,270
Columbiana	814	3.0	9.7	12,610
Coshocton	2,909	3.5	7.3	12,150
Gallia	331	3.2	11.3	11,420
Guernsey	1,143	2.6	10.3	12,020
Harrison	6,647	2.9	9.8	12,590
Hocking	480	1.8	9.6	11,780
Holmes	671	3.2	6.3	12,550
Jackson	677	2.4	8.0	11,630
Jefferson	4,137	2.7	9.9	12,650
Lawrence	149	3.8	13.2	11,110
Mahoning	412	2.0	6.9	13,000
Meigs	W	3.0	11.3	11,550
Monroe	1,115	3.4	14.4	11,690
Morgan	W	4.1	11.8	11,910
Muskingum	3,173	3.8	10.3	11,730
Noble	489	4.4	12.9	12,060
Perry	2,495	2.6	9.7	11,580
Stark	461	3.8	10.1	12,100
Tuscarawas	1,589	4.1	11.0	11,820
Vinton	1,677	3.2	9.9	11,670
Washington	76	4.9	13.6	11,800
Wayne	W	1.8	5.8	11,890
Undistributed	1,678	-	-	-
STATE TOTAL OR AVERAGE	46,768	2.8	10.1	12,070
PENNSYLVANIA				
Allegheny	3,957	2.1	8.9	13,250
Armstrong	7,189	2.1	9.6	13,110
Beaver	187	2.0	8.9	12,580
Bedford	W	1.5	11.2	13,600
Blair	W	1.5	9.9	12,800
Butler	1,373	2.3	10.1	12,800
Cambria	7,390	1.6	9.3	13,620
Centre	1,469	1.9	10.1	13,240
Clarion	5,336	2.6	10.3	12,850
Clearfield	8,124	1.6	10.0	13,220
Clinton	433	2.6	10.1	13,030
Elk	682	1.8	8.5	13,190
Fayette	2,816	1.7	10.0	13,210
Fulton	W	-	-	-
Greene	8,055	2.4	10.2	13,160
Huntingdon	W	1.5	9.7	13,610
Indiana	10,312	1.8	9.9	13,460
Jefferson	2,147	1.2	8.5	13,330
Lawrence	564	2.5	9.7	12,680
Lycoming	W	-	10.4	12,740
Mercer	336	2.6	9.5	12,510
Somerset	6,024	1.7	10.5	13,360
Tioga	W	1.8	13.8	12,970
Venango	451	1.6	11.0	12,670
Washington	13,360	2.0	9.8	12,840
Westmoreland	2,846	1.6	9.7	13,290
Undistributed	1,084	-	-	-
STATE TOTAL OR AVERAGE	84,135	1.8	9.7	13,280
TENNESSEE				
Anderson	1,848	2.1	8.6	13,340
Bledsoe	W	1.8	12.1	12,810
Campbell	1,703	1.0	7.4	13,260

TABLE A-1. (Continued)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
Claiborne	1,230	0.9	6.5	13,440
Cumberland	51	2.1	11.1	13,030
Fentress	216	2.5	9.9	13,050
Grundy	101	0.7	10.2	13,170
Marion	470	0.8	9.8	13,300
Morgan	576	2.2	6.9	13,720
Overton	W	3.4	11.4	12,710
Putnam	W	3.9	11.9	12,860
Roane	W	0.5	11.0	13,110
Scott	1,087	1.2	7.3	13,620
Sequatchie	605	1.6	11.5	13,040
Van Buren	26	2.1	11.8	12,770
White	W	3.5	10.0	13,070
Undistributed	293	-	-	-
STATE TOTAL OR AVERAGE	8,206	1.3	9.1	13,250
VIRGINIA				
Buchanan	14,016	0.8	8.2	13,720
Dickenson	5,357	0.6	8.2	13,890
Lee	1,077	0.8	7.0	13,270
Russell	2,085	0.5	7.4	13,850
Tazewell	2,542	0.6	6.2	14,180
Wise	10,433	0.6	9.4	13,330
STATE TOTAL OR AVERAGE	35,510	0.7	8.7	13,530
WEST VIRGINIA				
Barbour	3,672	3.0	10.0	13,260
Boone	9,675	0.8	7.8	13,380
Braxton	88	2.0	8.2	13,300
Brooke	741	2.3	11.5	11,940
Clay	68	0.7	9.6	13,040
Fayette	2,929	0.6	6.8	13,960
Gilmer	119	2.2	8.9	13,030
Grant	1,800	1.5	11.0	13,330
Greenbrier	846	1.0	6.0	13,970
Harrison	4,451	3.0	8.7	13,460
Kanawha	7,878	0.7	8.1	13,370
Lewis	714	3.0	9.3	12,960
Lincoln	W	1.3	8.2	12,460
Logan	8,148	1.0	7.7	13,450
McDowell	10,888	0.7	6.9	14,130
Marion	5,514	1.7	8.0	13,590
Marshall	5,266	4.2	10.7	12,900
Mason	295	2.8	12.4	11,560
Mercer	999	0.6	5.6	14,260
Mineral	357	1.5	9.4	13,770
Mingo	4,721	0.9	7.6	13,590
Monongalia	11,070	2.5	10.4	13,220
Nicholas	5,605	0.7	6.7	13,570
Ohio	W	3.6	10.0	12,760
Preston	2,559	1.8	10.1	13,330
Raleigh	6,222	0.7	5.8	14,230
Randolph	920	1.2	10.2	13,170
Summers	82	0.6	7.2	14,300
Taylor	171	2.0	8.7	13,130
Tucker	357	1.0	8.4	13,270
Upshur	1,998	2.3	9.0	13,250
Wayne	548	1.0	8.6	12,830
Webster	442	0.7	6.9	13,930
Wyoming	8,694	0.6	10.4	13,030
Undistributed	1,445	-	-	-
STATE TOTAL OR AVERAGE	109,282	1.5	8.2	13,540
EASTERN STATES TOTAL	537,505	-	-	-

FOOTNOTES TO TABLE A-1

- (a) The shipment figures, shown in Table 18 of Reference A-1 (Minerals Yearbook, 1975, Vol. 1, U.S. Bureau of Mines, published 1977) were assumed to be equivalent to the production figures for the states and counties. Entries designated by W indicate that the production values were withheld to avoid disclosing individual company confidential data.
- (b) Data on the average analysis of coals by state and county were taken from Table E-1 of Reference A-2 (Bureau of Mines Information Circular 8680, "The Reserve Base of U.S. Coals by Sulfur Content-1. The Eastern States", U.S. Bureau of Mines, 1975). The average analysis for sulfur content, ash content, and calorific value were based on the coal in the "as-received" condition.

TABLE A-2. PRODUCTION AND COAL CHARACTERISTICS DATA BY COUNTY
AND STATE - WESTERN REGION - 1975(a,b)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
ALASKA				
Yukon River	766	0.1	8.5	8,630
STATE TOTAL AND AVERAGE	766	0.1	9.7	9,440
ARIZONA				
Navajo	6,986	0.7	12.4	10,390
STATE TOTAL AND AVERAGE	6,986	0.8	15.5	10,350
ARKANSAS				
Franklin	W (a)	1.7	8.0	13,750
Johnson	W	2.2	8.8	13,690
Logan	35	1.9	10.9	13,530
Sebastian	W	-	-	-
Undistributed	454	-	-	-
STATE TOTAL OR AVERAGE	489	1.5	9.1	13,760
COLORADO				
Delta	W	0.5	6.1	11,910
Fremont	147	0.4	8.8	11,030
Garfield	1	0.8	7.4	12,130
Gunnison	1,070	0.4	6.1	12,690
Jackson	321	0.3	5.9	10,120
La Plata	W	1.4	7.2	13,120
Las Animas	632	0.5	13.3	12,640
Mesa	55	0.6	8.9	11,790
Moffat	W	0.2	3.8	11,510
Montrose	W	0.6	9.4	12,390
Pitkin	W	0.5	8.1	13,660
Rio Blanco	4	0.4	6.0	11,210
Routt	3,999	1.4	7.9	13,400
Weld	W	0.3	4.8	9,810
Undistributed	1,990	-	-	-
STATE TOTAL OR AVERAGE	8,219	0.5	7.2	11,160
IOWA				
Lucas	W	3.4	12.8	9,830
Mahaska	128	4.8	12.5	10,570
Marion	62	4.8	13.1	9,870
Monroe	W	3.3	13.4	10,290
Wapello	69	4.9	13.0	10,300
Undistributed	363	-	-	-
STATE TOTAL OR AVERAGE	622	4.6	13.6	9,930
KANSAS				
Bourbon	46	-	-	-
Cherokee	98	2.9	10.7	12,620
Crawford	335	2.7	13.4	11,920
STATE TOTAL OR AVERAGE	479	2.7	13.0	12,050
MISSOURI				
Barton	563	4.1	10.8	12,560
Bates	W	2.9	13.7	11,380
Henry	W	3.7	11.4	11,920
Howard	3	-	-	-
Macon	W	4.3	12.5	10,650
Putnam	353	3.7	10.4	9,910
Randolph	W	4.6	11.5	11,340
Vernon	242	4.8	12.7	12,200
Undistributed	4,477	-	-	-
STATE TOTAL OR AVERAGE	5,635	4.0	12.9	11,090

TABLE A-2. (Continued)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
MONTANA (Bituminous)				
Big Horn	W	0.3	3.4	9,500
Musselshell	W	0.5	8.5	10,660
Rosebud	W	0.6	7.2	9,080
Undistributed	21,752	-	-	-
STATE TOTAL OR AVERAGE	21,752	1.0	9.2	10,000
MONTANA (Lignite)				
Powder River	1	0.3	6.2	7,730
Richland	301	0.5	6.0	7,250
STATE TOTAL OR AVERAGE	302	0.5	6.0	7,250
NEW MEXICO				
Colfax	1,016	0.5	13.7	12,560
McKinley	468	0.5	8.6	11,310
San Juan	7,301	0.7	7.2	11,560
STATE TOTAL OR AVERAGE	8,785	0.6	10.0	11,900
NORTH DAKOTA				
Bowman	W	0.8	6.8	6,130
Burke	W	0.3	7.9	7,260
Grant	4	1.6	10.4	6,840
Mercer	3,743	0.5	6.8	7,200
Oliver	W	0.8	10.2	6,470
Stark	142	1.1	8.5	6,150
Ward	W	0.1	5.5	6,790
Williams	W	0.5	6.3	6,420
Undistributed	4,627	-	-	-
STATE TOTAL OR AVERAGE	8,516	0.4	6.8	7,030
OKLAHOMA				
Craig	1,275	3.5	9.9	12,560
Haskell	276	1.0	6.0	13,970
Le Flore	288	1.3	8.5	13,790
Muskogee	120	4.2	10.5	13,450
Nowata	34	-	-	-
Okmulgee	89	1.8	5.4	13,170
Pittsburg	120	1.3	7.8	13,100
Rogers	671	1.1	6.7	12,950
STATE TOTAL OR AVERAGE	2,873	2.0	7.5	13,150
TEXAS				
Freestone	W	1.3	9.8	8,000
Harrison	W	0.8	8.0	8,640
Milam	W	1.0	9.9	8,070
Titus	W	1.0	6.9	7,080
Undistributed	11,002	-	-	-
STATE TOTAL OR AVERAGE	11,002	1.5	11.7	10,200
UTAH				
Carbon	W	0.4	6.8	12,730
Emery	W	0.5	6.6	12,700
Sevier	W	0.6	7.8	11,830
Undistributed	6,961	-	-	-
STATE TOTAL OR AVERAGE	6,961	0.5	6.9	12,660
WASHINGTON				
King	17	0.6	11.2	10,860
Lewis	2,238	0.8	9.8	8,060
Thurston	1,487	1.4	11.9	8,720
STATE TOTAL OR AVERAGE	3,742	0.7	12.3	10,780

TABLE A-2. (Continued)

State and County	10 ³ Short Tons	Average Sulfur Content (b) Percent	Average Ash Content (b) Percent	Average Heating Value, (b) Btu/lb
WYOMING				
Campbell	W	0.6	6.5	8,100
Carbon	10,978	0.4	6.8	11,140
Converse	W	0.5	6.7	8,470
Hot Springs	W	0.5	6.1	11,080
Lincoln	W	0.6	4.3	10,690
Sheridan	W	0.4	4.5	9,630
Sweetwater	W	0.8	4.0	11,940
Undistributed	12,827	-	-	-
STATE TOTAL OR AVERAGE	23,804	0.5	5.0	10,630
WESTERN STATES TOTAL	110,934	-	-	-

- (a) Production data are from Table 18 of Reference A-1 (U.S. Bureau of Mines, Minerals Yearbook, 1975). Entries designated by W indicate that the production values were withheld to avoid disclosing individual company confidential data.
- (b) Data on the average analyses of coals by state and county were taken from Table D of Reference A-3 (Bureau of Mines Information Circular 8693, "The Reserve Base of U.S. Coals by Sulfur Content - 2. The Western States"). The average analyses for sulfur content, ash content, and calorific value were based on the coal in the "as-received" condition.

TABLE A-3. 1975 PRODUCTION OF BITUMINOUS AND LIGNITE COALS BY STATE
VERSUS SULFUR CONTENT, 10³ SHORT TONS(a)

State	Range of Sulfur Content, percent											Total Production
	<0.40	0.40-0.59	0.60-0.79	0.80-0.99	1.00-1.39	1.40-1.79	1.80-2.19	2.20-2.59	2.60-2.99	3.00-3.39	> 3.4	
Eastern Region												
Alabama	--	576	747	1,730	19,076	49	--	--	--	--	476	22,654
Georgia	--	--	--	--	--	--	--	--	--	--	74	74
Illinois	--	--	--	--	6,011	--	5,904	2,040	55	14,313	9,813	21,400
Indiana	--	--	--	--	11	--	34	5,560	1,112	141	547	17,718
Kentucky (Eastern)	--	74	6,400	47,825	26,297	984	187	1,822	836	--	--	2,831
Kentucky (Western)	--	--	--	--	731	--	--	199	--	856	44,616	9,954
Maryland	--	--	--	--	952	--	--	--	--	--	--	56,356
Ohio	--	--	--	--	--	--	1,654	--	--	--	--	2,606
Pennsylvania	--	--	--	--	--	128	892	677	14,422	3,728	25,243	1,678
Tennessee	--	--	--	--	2,147	27,200	37,156	9,992	6,105	--	451	46,168
Virginia	--	--	--	--	2,790	605	1,925	792	--	--	--	8,206
West Virginia	--	2,085	18,332	15,093	--	--	--	--	--	--	--	35,510
Subtotals	--	2,735	69,387	80,744	68,834	36,637	2,818	13,928	295	8,837	5,266	109,282
							50,570	35,010	22,825	27,875	85,936	56,953
												537,506
Western Region												
Alaska	766	--	--	--	--	--	--	--	--	--	--	766
Arizona	--	--	6,986	--	--	--	--	--	--	--	--	6,986
Arkansas	--	--	--	--	--	--	35	--	--	--	454	489
Colorado	321	1,853	55	1	--	3,999	--	--	--	--	1,990	8,219
Iowa	--	--	--	--	--	--	--	--	--	--	363	622
Kansas	--	--	--	--	--	--	--	--	433	--	46	479
Missouri	--	--	--	--	--	--	--	--	--	--	--	5,635
Montana (bituminous)	--	--	--	--	21,752	--	--	--	--	--	1,158	4,477
Montana (lignite)	1	301	--	--	--	--	--	--	--	--	--	21,752
New Mexico	--	1,484	7,301	--	--	--	--	--	--	--	--	302
North Dakota	--	3,743	--	--	142	4	--	--	--	--	4,627	8,516
Oklahoma	--	--	--	--	1,355	--	89	--	--	1,395	34	2,873
Texas	--	--	--	--	--	11,002	--	--	--	--	--	11,002
Utah	--	6,961	--	--	--	--	--	--	--	--	--	6,961
Washington	--	--	17	2,238	--	1,487	--	--	--	--	--	3,742
Wyoming	--	23,804	--	--	--	--	--	--	--	--	--	23,804
Subtotals	1,088	38,146	14,359	2,239	23,249	16,492	124	--	433	--	2,812	110,933

(a) Sources: References A-1, A-2, and A-3.

in the range 1.00-2.19 percent. Of the remaining production, 16 percent had sulfur content between 2.20 and 3.39 percent sulfur and 16 percent contained more than 3.40 percent sulfur. The sulfur content was unknown for 11 percent of the coal.

In the western region, 55.8 million short tons, or 50 percent of the western production, contained less than 1 percent sulfur. Another 39.9 million short tons, or 36 percent, had sulfur values in the range 1.00-1.19 percent, while 11 percent had unknown sulfur content.

For some of the western states, insufficient data were available to show the relation between production and sulfur content. The original reference did not show production for certain counties because to do so would disclose confidential information as noted in the first footnote to Table A-2. The states most affected were Alaska, Arizona, Montana, Texas, Utah, and Wyoming. For these states the actual distribution of sulfur content would be broader than indicated in Table A-3.

Projection of Coal Production Through 1985

The results of an industry-wide survey on new coal mine capacity completed in mid-January 1978 by Keystone Coal Industry Manual^(A-5) were used as a basis to project coal production for the period 1975 through 1985.

The Keystone survey showed that coal mines in development, expansion, or planning stages would add more than 715 million tons of new capacity to the nation's total by the end of 1985. The survey covered 22 states and included the principal coal-producing states in the nation. Of the 391 mines covered in the survey, 122 were already producing coal prior to 1977. These 122 mines presently account for about 150 million tons, and many of these mines anticipate considerable growth through 1985. The companies involved in large expansion programs were the producers of about 69 percent of the nation's total output of about 680 million tons of coal in 1976.

The three growth scenarios listed below were used for projecting yearly coal production for individual states for the period 1975 through 1985:

Scenario M - Medium or intermedium growth (as forecast in
Keystone survey)

Scenario L - Low growth (M multiplied by 0.5)

Scenario H - High growth (M multiplied by 1.25).

Projected data for the eastern states are given in Table A-4 and for the western states in Table A-5. The average sulfur content of the coals for the individual states also is shown in Tables A-4 and A-5. Projected coal production data for the eastern and western regions and the entire United States are summarized in Table A-6. The M (medium or intermediate growth) scenario was assumed to correspond to the growth of new coal capacity as forecast by the Keystone survey^(A-5). The alternative growth scenarios were derived by multiplying the Keystone capacity increment for each year by the factor 1.25 for the H scenario and by the factor 0.5 for the L scenario.

The resulting projected coal production for the eastern states increased from 538 to 639 million tons (about 20 percent) for the M scenario and decreased from 538 to 531 million tons (~ 1 percent) for the L scenario for the period from 1975 through 1985. The minor decrease in production in the L scenario results from the inclusion of a capacity depletion of 13.5 million tons per year for the eastern states. In contrast, the projected coal production for this same period for the western states increased from 111 to 713 million tons for the M scenario and from 111 to 422 for the L scenario. For the total United States, the projected annual coal production increased from a value of 649 million tons to 1352 million tons for the M scenario and to 953 million tons for the L scenario. The largest growth in new coal mine capacity is expected to occur in Wyoming, Montana, Texas, New Mexico, North Dakota, and Colorado in that order.

Comments on Various Growth Scenarios

The projections based on the H and M scenarios are generally higher than the coal production estimates shown in Table A-7 for 1985 from other sources as cited in the September 1977 Comptroller General's Report to Congress from the General Accounting Office (GAO)^(A-6) and in President Carter's National Energy Plan^(A-7). For example, the Edison Electric Institute^(A-8) projects coal production of 779 million tons annually by 1985; the Bureau of Mines^(A-9) estimates 988 million tons; the GAO predicts about 1 billion tons; and the National Energy Plan calls for 1.2 billion tons. The coal-production rate for 1985 in the L scenario is in fairly good agreement with the Bureau of Mines and the GAO production projections of about

TABLE A-4. PROJECTION OF COAL PRODUCTION, EASTERN REGION, 1975-1985,
FOR THREE GROWTH SCENARIOS (a,b)

State	Scenario (a)	Average Sulfur Content, percent	Coal Production, million short tons											
			1975 (c)	1976 (d)	1977	1978	1979	1980	1981	1982	1983	1984	1985	
Alabama	H	--	--	--	24.79	28.41	33.65	36.93	37.61	39.67	39.48	39.41	39.22	
	M	1.0	22.64	22.98	24.31	27.09	31.17	33.68	34.11	35.64	35.37	35.20	34.93	
	L	--	--	--	23.36	24.47	26.23	27.20	27.13	27.61	27.19	26.82	26.40	
Georgia	H	--	--	--	1.01	1.01	1.01	1.00	1.00	1.00	1.00	1.00	1.00	
	M	1.4	0.074	0.074	0.82	0.82	0.82	0.81	0.81	0.81	0.81	0.81	0.81	
	L	--	--	--	0.45	0.45	0.45	0.44	0.44	0.44	0.44	0.44	0.44	
Illinois	H	--	--	--	68.41	78.21	82.84	86.84	91.78	94.53	95.53	97.41	96.66	
	M	2.9	59.54	60.66	65.56	74.11	77.51	80.41	84.06	85.96	86.46	87.66	86.76	
	L	--	--	--	62.86	65.94	66.89	67.59	68.67	68.87	68.37	68.22	67.02	
Indiana	H	--	--	--	27.60	29.10	30.85	30.47	29.84	32.59	33.21	34.46	35.08	
	M	2.6	25.12	26.35	27.22	28.29	29.56	29.13	28.50	30.57	30.94	31.81	32.18	
	L	--	--	--	26.47	26.69	27.01	26.48	25.85	26.57	26.44	26.56	26.43	
Kentucky (Eastern)	H	--	--	--	91.99	103.06	105.75	108.12	109.18	110.18	111.87	113.56	117.75	
	M	1.0	87.26	87.83	90.72	99.14	100.85	102.31	102.72	103.08	103.99	104.90	107.81	
	L	--	--	--	88.18	91.30	91.06	90.70	89.81	88.90	88.26	87.62	87.98	
Kentucky (Western)	H	--	--	--	59.46	59.74	60.52	60.05	59.27	59.11	60.58	61.17	60.51	
	M	3.6	56.36	56.87	58.66	58.60	58.94	58.28	57.37	56.96	57.85	58.04	57.23	
	L	--	--	--	57.06	56.33	55.80	54.77	53.61	52.70	52.44	51.83	50.72	
Maryland	H	--	--	--	2.80	3.37	4.31	4.63	4.57	4.51	4.45	4.39	4.33	
	M	1.3	2.61	2.61	2.75	3.19	3.93	4.17	4.11	4.05	3.99	3.93	3.87	
	L	--	--	--	2.65	2.84	3.18	3.27	3.21	3.15	3.09	3.03	2.97	
Ohio	H	--	--	--	49.87	53.08	55.79	58.12	57.95	57.53	57.11	56.32	55.28	
	M	2.8	46.77	47.54	49.17	51.50	53.43	55.06	54.69	54.12	53.55	52.68	51.61	
	L	--	--	--	47.77	48.35	48.73	48.96	48.19	47.32	46.45	45.43	44.31	

TABLE A-4. (Continued)

State	Scenario (a)	Average Sulfur Content, percent	Coal Production, million short tons										
			1975 (c)	1976 (d)	1977	1978	1979	1980	1981	1982	1983	1984	1985
Pennsylvania	H	--	--	--	90.95	95.70	98.54	100.71	100.85	100.38	99.80	97.98	95.87
	M	1.8	84.14	85.28	89.39	92.77	94.62	95.90	95.59	94.79	93.90	92.02	89.91
	L	--	--	--	86.28	86.92	86.79	86.38	85.17	83.72	82.22	80.23	78.12
Tennessee	H	--	--	--	9.00	8.79	8.58	8.37	8.16	7.95	7.74	7.53	7.32
	M	1.3	8.21	8.21	8.80	8.59	8.38	8.17	7.96	7.75	7.54	7.33	7.12
	L	--	--	--	8.40	8.19	7.98	7.77	7.56	7.35	7.14	6.93	6.72
Virginia	H	--	--	--	35.56	36.11	36.47	36.52	37.26	36.60	36.90	36.10	35.21
	M	0.7	35.51	35.51	35.37	35.63	35.74	35.60	36.01	35.30	35.36	34.54	33.65
	L	--	--	--	35.00	34.69	34.30	33.79	33.55	32.75	32.34	31.49	30.60
West Virginia	H	--	--	--	123.07	136.95	145.95	149.95	150.18	152.31	149.82	147.08	144.34
	M	1.5	109.28	110.97	120.10	130.65	137.30	119.95	139.58	140.73	138.19	135.45	132.71
	L	--	--	--	114.17	118.08	120.04	120.00	118.45	117.66	115.02	112.28	109.54
Eastern States Total	H	--	--	--	584.51	633.53	664.26	681.71	687.65	696.36	697.49	696.41	692.57
	M	--	537.51	544.88	572.87	610.38	632.25	643.47	645.51	649.76	647.95	644.37	638.59
	L	--	--	--	552.65	564.25	568.46	567.35	561.64	557.04	549.40	540.88	531.25

(a) Scenario M (intermediate growth) was assumed to correspond to the growth of new coal capacity as forecast by the Keystone Coal Industry Manual survey (A-5). Scenario H (high growth) was based on a capacity growth equivalent to 125% of M. Scenario L was based on a capacity growth equivalent to 50% of M.

(b) For the eastern states a depletion of production capacity of 13.5 million tons per year was assumed to occur. This loss of production was prorated among the eastern states according to 1975 production.

(c) Production data for 1975 are from the U.S. Bureau of Mines Minerals Yearbook (A-1).

(d) Production for 1976 was assumed to have increased by 28 million tons over 1975; estimates of 1976 production ranged from about 665 to 680 million tons (A-5, A-6). The 28-million-ton increase was prorated according to the present capacity of existing mines covered by the Keystone survey (A-5).

TABLE A-5. PROJECTION OF COAL PRODUCTION, WESTERN REGION, 1975-1985,
FOR THREE GROWTH SCENARIOS (a,b)

State	Scenario (a)	Average Sulfur Content, percent	Coal Production, million short tons											
			1975 (c)		1976 (d)	1977	1978	1979	1980	1981	1982	1983	1984	1985
Alaska (b)	H	--	--	--	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
	M	0.1	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
	L	--	--	--	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Arizona	H	--	--	--	10.75	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
	M	0.7	6.99	7.87	10.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
	L	--	--	--	9.02	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52	9.52
Arkansas (b)	H	--	--	--	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
	M	1.5	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
	L	--	--	--	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Colorado	H	--	--	--	15.07	25.17	36.00	49.19	57.75	67.25	73.65	75.15	84.90	84.90
	M	0.55	8.22	9.16	13.89	21.99	30.66	41.21	48.06	55.66	60.76	61.96	69.76	69.76
	L	--	--	--	11.53	15.58	19.92	25.20	28.63	32.43	34.98	35.58	39.48	39.48
Iowa (b)	H	--	--	--	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
	M	4.6	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
	L	--	--	--	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Kansas	H	--	--	--	0.52	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
	M	2.7	0.48	0.52	0.52	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
	L	--	--	--	0.52	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Missouri (b)	H	--	--	--	7.05	7.05	7.05	7.05	7.05	7.05	7.05	7.05	7.05	7.05
	M	4.0	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
	L	--	--	--	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
Montana	H	--	--	--	27.24	31.49	44.29	54.79	72.10	84.98	90.98	94.73	103.48	103.48
	M	1.0	22.05	27.24	27.24	30.64	40.84	49.25	63.10	73.40	78.20	81.20	88.20	88.20
	L	--	--	--	27.24	28.94	34.04	38.25	45.18	50.33	52.73	54.23	57.73	57.73
New Mexico	H	--	--	--	12.63	17.26	22.89	28.27	33.65	44.28	53.41	58.78	69.04	69.04
	M	0.6	8.79	10.88	12.28	15.98	20.48	24.78	29.08	37.58	44.88	49.18	57.38	57.38
	L	--	--	--	11.58	13.43	15.68	17.83	19.98	24.23	27.88	30.03	34.13	34.13

TABLE A-5. (Continued)

State	Scenario (a)	Average Sulfur Content, percent	Coal Production, million short tons										
			1975 (c)	1976 (d)	1977	1978	1979	1980	1981	1982	1983	1984	1985
North Dakota	H	--	--	--	14.05	21.55	22.30	27.43	41.68	49.18	50.93	67.31	73.06
	M	0.4	8.52	10.47	13.33	19.33	19.93	24.03	35.43	41.43	42.83	55.93	60.53
	L	--	--	--	11.90	14.90	15.20	17.25	22.95	25.95	26.65	33.20	35.50
Oklahoma	H	--	--	--	3.02	3.40	4.15	4.65	4.90	5.15	5.53	5.66	5.79
	M	2.0	2.87	2.89	2.99	3.29	3.89	4.29	4.49	4.69	4.99	5.09	5.19
	L	--	--	--	2.94	3.09	3.39	3.59	3.69	3.79	3.94	3.99	4.04
Texas	H	--	--	--	18.08	25.31	35.31	46.31	57.31	67.06	75.19	83.69	84.32
	M	1.5	11.00	13.58	17.18	22.96	30.96	39.76	48.56	56.36	62.86	69.66	70.16
	L	--	--	--	15.38	18.27	22.27	26.67	31.07	34.97	38.22	41.62	41.87
Utah	H	--	--	--	13.84	21.22	24.41	34.60	40.20	45.09	51.13	62.76	75.05
	M	0.5	6.96	8.21	12.71	18.61	21.16	29.31	33.79	37.70	42.53	51.83	61.66
	L	--	--	--	10.46	13.41	14.69	18.77	21.01	22.97	25.39	30.04	34.96
Washington	H	--	--	--	5.74	5.74	5.74	5.74	5.74	5.74	5.74	5.74	5.74
	M	0.7	3.74	4.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49
	L	--	--	--	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99	4.99
Wyoming	H	--	--	--	51.29	72.54	111.17	161.05	199.36	232.17	265.38	298.26	336.39
	M	0.5	23.80	28.75	46.78	63.78	94.68	134.58	165.23	191.48	218.05	244.35	274.85
	L	--	--	--	37.77	46.27	61.72	81.67	97.00	110.13	123.42	136.57	151.82
Western States Total	H	--	--	--	181.63	245.79	328.37	434.14	534.80	622.92	694.05	774.10	859.88
	M	--	110.94	131.58	170.10	221.43	287.45	372.18	452.59	523.15	579.95	644.05	712.58
	L	--	--	--	150.85	176.52	209.54	251.86	292.14	327.43	355.84	387.89	422.16

(a) Scenario M (intermediate growth) was assumed to correspond to the growth of new coal capacity as forecast by the Keystone Coal Industry Manual survey (A-5). Scenario H (high growth) was based on a capacity growth equivalent to 125% of M. Scenario L was based on a capacity growth equivalent to 50% of M.

(b) Production values for states not covered by the Keystone survey were assumed to be the same for the period 1977 through 1985 as those shown for 1975 for Scenarios M and L and were increased by a factor of 1.25 for Scenario H.

(c) Production data for 1975 are from the U.S. Bureau of Mines Minerals Yearbook (A-1).

(d) Production for 1976 was assumed to have increased by 28 million tons over 1975; estimates of 1976 production ranged from about 665 to 680 million tons (A-5, A-6). The 28-million-ton increase was prorated according to the present capacity of existing mines covered by the Keystone survey (A-5).

TABLE A-6. PROJECTION OF TOTAL COAL PRODUCTION, EASTERN AND WESTERN STATES AND OVERALL UNITED STATES, 1975-1985, FOR THREE GROWTH SCENARIOS (a,b)

Region	Scenario (a)	Coal Production, million short tons											Ratio of 1985 to 1975 Production
		1975 (c)	1976 (d)	1977	1978	1979	1980	1981	1982	1983	1984	1985	
Eastern States (b)	H	--	--	585	634	664	682	688	696	697	696	693	1.29:1
	M	538	545	573	610	632	643	646	650	648	644	639	1.19:1
	L	--	--	553	564	568	567	562	557	549	541	531	0.987:1
Western States (b)	H	--	--	182	246	328	434	535	623	694	774	860	7.75:1
	M	111	132	170	221	287	372	453	523	580	644	713	6.42:1
	L	--	--	151	177	210	252	292	327	356	388	422	3.80:1
Total United States	H	--	--	767	880	992	1,116	1,223	1,319	1,391	1,470	1,553	2.39:1
	M	649	677	743	831	919	1,015	1,099	1,173	1,228	1,288	1,352	2.08:1
	L	--	--	704	741	778	819	854	884	905	929	953	1.47:1

(a) Scenario M (intermediate growth) was assumed to correspond to the growth of new coal capacity as forecast by the Keystone Coal Industry Manual survey (A-5). Scenario H (high growth) was based on a capacity growth equivalent to 125% of M. Scenario L was based on a capacity growth equivalent to 50% of M.

(b) For the eastern states a depletion of production capacity of 13.5 million tons per year was assumed to occur. This loss of production was prorated among the eastern states according to 1975 production. For the western states, production values for states not covered by the Keystone survey were assumed to be the same for the period 1977 through 1985 as those shown for 1975 for Scenarios M and L and were increased by a factor of 1.25 for Scenario H.

(c) Production data for 1975 are from the U.S. Bureau of Mines Minerals Yearbook (A-1).

(d) Production for 1976 was assumed to have increased by 28 million tons over 1975; estimates of 1976 production ranged from about 665 to 680 million tons (A-5, A-6). The 28-million-ton increase was prorated according to the present capacity of existing mines covered by the Keystone survey (A-5).

TABLE A-7. PROJECTIONS OF COAL PRODUCTION FOR THE UNITED STATES
FOR 1985 ACCORDING TO DIFFERENT SCENARIOS

Scenario	Production, million short tons	
	1975 (Actual)	1985
Edison Electric Institute (low growth) ^(a)	648	779
Bureau of Mines ^(b)	648	988
President Carter's Goal (National Energy Plan) ^(c)	648	1,200
General Accounting Office ^(d)	648	~1,000
H (high growth) ^(e)	648	1,550
M (medium growth) ^(e)	648	1,350
L (low growth) ^(e)	648	950

(a) Reference A-8.

(b) Reference A-9.

(c) Reference A-7.

(d) Reference A-6.

(e) See text and Tables A-4, A-5, and A-6 for basis and description of these growth scenarios.

1 billion tons. The L scenario is also considered to represent the most probable (i.e., of the H, M, and L scenarios herein) projection of coal production that will actually be achieved by the end of 1985.

The GAO, as a result of the exhaustive study it carried out for Congress on "U.S. Coal Development--Promises, Uncertainties" (A-6), believes that achieving coal production and use of 1.2 billion tons as proposed by the Administration is highly unlikely. GAO, in fact, believes it will be very difficult to achieve 1 billion tons annually by 1985.

In light of the GAO, Bureau of Mines, and National Energy Plan estimates, it appears that the projected coal production values of M scenario, which were based on the Keystone survey, are probably somewhat overoptimistic, since they exceed the National Energy Plan production goal of 1.2 billion tons in 1985 by about 150 million tons. It should be noted that the projected values in the M scenario were based on new mine capacity estimates rather than on coal demand.

The H scenario represents an extremely large expansion of coal production to 1,550 million tons annually by 1985. The three conditions under which the H scenario might be implemented are cited below.

- (1) Very high rate of expansion of the economy and energy use.
- (2) Drastic curtailment of imported oil and gas supplies because of a Mideast war or other international crisis, along with a sharp cut-off of domestic natural gas supplies.
- (3) Drastic curtailment of nuclear power generation, including existing plants and plants under construction or in design or planning stages because of abnormal safety and environmental concerns and requirements.

All three of the above conditions would essentially have to occur simultaneously for an H scenario to become probable. As none of the conditions is expected to exist during the 1977-85 period, the probability of the high coal production growth as projected by Scenario H appears very low.

Among the coal production projection shown for the various scenarios in Tables A-4, A-5, and A-6, the level M scenarios appear to cover the more probable ranges of coal production that will occur in 1985. Thus, these tables are useful in that they show anticipated new coal production values for the various states and regions, together with providing data

on the average sulfur content of the coals in the various states where much of the expansion in new or existing mine capacity is expected to occur.

References for Appendix A

- (A-1) U.S. Bureau of Mines, Minerals Yearbook, 1975, 1, Table 18, U.S. Government Printing Office, Washington, D.C. (1977).
- (A-2) Thomson, R. D., and York, H. F., "The Reserve Base of U.S. Coals by Sulfur Content - 1. The Eastern States", Table E, U.S. Bureau of Mines Information Circular 8680 (1975).
- (A-3) Hamilton, P. A., White, D. H., Jr., and Matson, T. K., "The Reserve Base of U.S. Coals by Sulfur Content - 2. The Western States", Table D, U.S. Bureau of Mines Information Circular 8693 (1975).
- (A-4) Cavallaro, J. A., Johnston, M. T., and Deurbrouck, A. W., "Sulfur Reduction Potential of the Coals of the United States - A Revision of RI 7633", U.S. Bureau of Mines RI 8118 (1976).
- (A-5) Nielsen, G. F., "Keystone Forecasts 765 Million Tons of New Coal Capacity by 1987", Coal Age, 83, No. 2, pp 113, 114, 116, 118, 120, 122, 124, 126, 128, 130, 132, 134 (February, 1978).
- (A-6) Comptroller General of the United States, "U.S. Coal Development - Promises, Uncertainties", Report to the Congress, U.S. General Accounting Office, EMD-77-43, Washington, D.C., (September 22, 1977).
- (A-7) "The National Energy Plan", Executive Office of the President, Energy Policy and Planning, Washington, D.C. (April 29, 1977).
- (A-8) Edison Electric Institute, Economic Growth in the Future, McGraw-Hill, New York (1976).
- (A-9) Dupree, W. G., and Corsentino, J. S., "United States Energy Through the Year 2000" (revised), Bureau of Mines, Government Printing Office, Washington, D.C. (1975).

APPENDIX B

CONSTRAINTS TO GROWTH IN COAL PRODUCTION

APPENDIX B

CONSTRAINTS TO GROWTH IN COAL PRODUCTION

Introduction

In Appendix A it was projected that coal production by 1985 would fall in the general range of about 900 to 1300 million tons per year. Possible constraints that may affect the ability of the coal industry to achieve such levels of production are considered in this appendix.

Results of the survey conducted for the Federal Energy Administration by ICF, Incorporated^{(B-1)*}, of projected mine openings by 1985 identified over 300 planned and possible coal mine developments among existing and potential coal producers. The survey concluded that over a billion tons could be produced by 1985. The results of GAO discussions with 11 major coal producers (including 9 of the top 15 producers in 1975) showed that all believed the industry could double production by 1985 and triple production by 2000 under existing conditions^(B-2).

The Keystone survey (completed in mid-January, 1978) of coal mines in development, expansion, or planning states showed that more than 715 million tons of new capacity would be added to the nation's total by the end of 1985^(B-3). The results of this survey are reflected by the M scenario, which projects a total coal production capacity for the nation in 1985 of 1.35 billion tons per year.

On the basis of the findings of the ICF and Keystone surveys and the GAO discussions, it appears that coal industry representatives are confident that doubling of coal production from 1975 levels could be achieved by 1985.

Although not doubting the possible achievement of the above predictions, GAO strongly believes that realization of a doubling of coal production by 1985 would require that many conditions be met^(B-2). These include the following.

* References for Appendix B are listed on page 257.

- Coal companies would have to possess the foresight and capital to open mines when added production is needed.
- Mine equipment manufacturers would have to be geared up to fill orders promptly.
- Good labor-management relations must be established to minimize or avoid prolonged strikes and work interruptions.
- Coal mining productivity (tons produced per worker day) must improve. Improvements in mining technology and increased employee motivation are possible ways to increase productivity.
- New workers must be found and trained. This includes mining engineers as well as miners.
- Mining technology must be improved. This can be achieved by increased research and development on new and more efficient equipment and by the development of innovative or improved mining techniques.

Time Requirements for New Mine Openings

Bureau of Mines (BOM) estimates of the time requirements for the various tasks or steps involved in opening up new surface and underground mines in both the east and west are shown in Table B-1^(B-2,B-4). The amount of time required for each task is influenced by the location of the mine, size and capacity of the mine, ownership type, and environmental considerations. Since some of the tasks, shown in Table B-1, can be performed simultaneously with others, the total length of time needed may be less than those shown.

The longer time spans needed for the west are primarily the result of environmental and other government considerations (Tasks 5, 7, and 8). For example, typical minimum and maximum times for these tasks range from 1.5 to 6.0 years for underground mines and 2.5 to 7.5 years for surface mines.

From the above discussion, and the data cited in Table B-1, it is apparent that extended time requirements, for mine openings (e.g., those ranging from about 6 to 10 years or more) could cut down greatly on new coal production available by 1985. However, with careful planning and procurement, the coal industry companies feel that sufficient new mine openings can be successfully achieved so that doubling of the nation's coal production in 1975 could be achieved by 1985.

TABLE B-1. ESTIMATED TIME REQUIREMENTS FOR OPENING UP NEW MINES (a)

Task No.	Task	Surface Mines, years				Underground Mines, years			
		East		West		East		West	
		Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
1	Initial examination	0.10	0.20	0.15	0.50	0.10	0.20	0.10	1.50
2	Mine assembly	0.15	0.30	0.25	1.50	0.15	0.30	0.20	2.00
3	Cost analysis	0.00	0.10	0.10	0.50	0.00	0.25	0.10	0.50
4	Market development	0.00	0.15	0.10	0.50	0.00	0.15	0.10	0.50
5	Environmental and related studies	0.00	0.10	0.50	1.50	0.00	0.10	0.25	1.50
6	Preliminary design and equipment selection	0.50	0.75	0.50	1.50	0.75	1.00	0.50	1.00
7	NEPA process (b)	0.00	0.00	1.50	4.00	0.00	0.00	1.00	3.00
8	Permits	0.25	0.50	0.50	2.00	0.25	0.50	0.25	1.50
9	Design and construction	0.50	0.75	0.30	2.00	0.75	1.25	0.30	2.00
10	Mining preparation	0.00	0.15	0.10	0.50	0.50	1.25	0.20	1.00
	Total	1.50	3.00	4.00	15.00	2.50	5.00	3.00	13.50

(a) Data are from Bureau of Mines and Government Accounting Office sources (References 6 and 15).

(b) The National Environmental Policy Act (NEPA) process involves the steps taken by the government in assessing the environmental impact of the mining of Federal lands.

Availability of Mining Personnel

Underground mine operators, interviewed by GAO, did not believe there would be a problem in securing new mining job applicants^(B-2). These views are supported by various studies on coal's future, which concluded that, although the hazards are great, they would be offset substantially by other factors, such as improved safety conditions, unemployment trends, compensation differential, and fringe benefits. Accordingly, these studies predicted that there would be sufficient applicants for potential openings. Recent increases in mine employment during the past few years tend to indicate further that there will be enough applicants.

During the past few years there has been a significant increase in the number of students and graduate students in mining engineering, metallurgical and mineral processing engineering, and mineral economics. The enrollment increased from 2,970 in 1974-75 to 3,638 in 1975-76^(B-5).

According to the information and data presented above, sufficient numbers of miners and mining engineers should be available by 1985 so that lack of adequate personnel in the mining industry will not be a constraint to coal production in 1985.

Availability of Mining Equipment

Timing of procurement is important as most modern coal mining equipment is not mass-produced. Common and standard equipment is generally delivered within a minimum amount of time, but larger, more sophisticated equipment will take longer. The BOM indicated that some equipment can take from 6 months to 4 years to manufacture, depending on its complexity^(B-4). The availability of raw materials and the manufacturer's productive capacity also affect equipment delivery time.

Recent studies performed by BOM and by a consultant firm for FEA have indicated that equipment availability would generally present no great problems or constraints to coal production in 1985^(B-4, B-6).

Financing Considerations

Capital investment needed to expand future coal production will be substantial compared with current rates of investment in the industry. If

government policies are established in a way to assure long-term markets for coal, there should be no financial constraints to increased production at optimum prices.

Financing for coal mine expansion has been cited by some authorities as a possible constraint to increasing coal production. However, financing is readily available to any mining concern with long-standing contracts with its customers^(B-7). These contracts can be used as collateral to provide financing for new operations. If the demand for coal continues to increase, then the desire for contracts by coal users will also increase, as will the collateral^(B-8).

GAO discussions with economists and experts in the coal mining and financial communities indicated a consensus that future coal projects should be able to receive financing so long as increased coal demand develops as expected^(B-2).

Summary

Of the possible constraints to coal production considered, none seems likely to preclude the achievement of the various levels of coal production forecasted. The major problem is that coal companies need lead time for expansion of production and clear signals of the need for expansion must be given. Projections of increased coal demand made over recent years have not materialized and the coal industry has suffered as a result. If increased production is required in the future, increased demand must signal that need.

References for Appendix B

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APPENDIX C

CHARACTERIZATION OF COAL CONTRACTS

APPENDIX C

CHARACTERIZATION OF COAL CONTRACTS

Introduction

The two purposes of the analysis in this appendix are to describe and analyze supply contracts between coal companies and coal consumers, mainly electric utilities and major industrial coal consumers, and to assess the extent to which existing contractual obligations either promote or discourage coal cleaning as a sulfur emissions control strategy.*

At least three types of conditions may occur which would suggest adoption of physical coal cleaning (PCC) by a utility or industrial coal burner.

Scenario Case 1. Revision of State Implementation Plan (SIP) SO₂ emission standards, or tighter enforcement of existing SIPs, such that cleaned coal must be burned in order to meet the revised standards.

Scenario Case 2. Cost and/or technology changes with respect to mining practices, transportation systems, combustion technologies, or even selective government subsidies, which make physical coal cleaning the most economically attractive pollution control option.

Scenario Case 3. Promulgation of new regulations limiting the sulfur content of coals sold in selected regions.

As a result of any of these scenarios, either singly or in concert, existing contractual arrangements between coal companies and users might be a critical factor in determining the users' response. For example, it is likely that as an aftermath of tightened SIP's a coal user might be stuck with contracts for high-sulfur coal that could not be cleaned to meet the more stringent standard. In such an event, such a contract could well

* This appendix is based on a report submitted by Teknekron under a subcontract on this program.

serve as an obstacle to PCC. Similarly, contractual obligations to purchase uncleaned coal might discourage a utility or industry from accepting an attractive offer of cleaned coal from a coal company in competition with the utility's current supplier if it is surmised that the cost of breaking the current contract is too great. These contractual obstacles to PCC, however, apply only in the case of long-term coal contracts. To the extent that coal purchases are in the spot market or involve relatively short-term periods, such potential barriers never materialize.

Even in the common case of long-term obligations, however, the question of contractual impact on the coal users' decision-making process is problematic. Most coal contracts are similar but by no means identical. In any event, different contract provisions become relevant depending upon which of the above hypothetical scenarios occurs. The "compliance with antipollution laws" or force majeure (act of God) provisions of coal-supply contracts would be relevant under Case 1, "economic hardship" clauses under Case 2, and "price adjustment" provisions under Case 3. (As subsequently illustrated, the first two cases primarily affect user response, while the third affects mainly the suppliers' decision-making.)

Accordingly, this appendix is divided into five sections. The first section discusses the length of coal supply contracts and the reasons for choice of contract duration. It addresses the threshold question of where long-term coal-supply contracts exist and, hence, present a potential barrier to PCC. The following three sections anticipate scenarios as in Case 1, Case 2, and Case 3, respectively. Each section describes the relevant contract provisions which would become operational in the given scenario and then looks at the potential affect of those clauses on the PCC option. The discussions focus on the question of whether various contract clauses would in fact serve as obstacles to PCC from either the user's or the supplier's point of view. Finally, a concluding section summarizes our findings on the extent to which existing contracts inhibit adoption of PCC and suggests a way in which existing long-term contracts might be used to facilitate physical coal cleaning.

Duration of Coal Supply Contracts

Utility Sector

Most coal purchases in the utility sector are pursuant to long-term contracts.* Spot market purchases represent approximately 15 to 20 percent of all coal sales to utility companies in a normal calendar year as shown by the following data from the Federal Power Commission.

<u>Year</u>	<u>Fraction of Utility Purchases in the Spot Market, percent</u>
1973	19.4
1974	24.1
1975	18.5
1976	14.0
1977 (first six months)	15.8

Most utility spot purchases are in the eastern coal market. For example, spot sales of Alabama, Ohio, and Pennsylvania coal in 1976 represented between 20 percent and 30 percent of the statewide markets. In contrast, spot sales of coal in Montana, Wyoming, and New Mexico ranged from 0 to 3 percent.

There are several reasons why utilities go to the spot market for coal, even though prices there are often higher than in the long-term market. Among these are the following:

- Unusual weather patterns which create unexpected seasonal increases in electricity demand
- Interruptions in delivery of supplies under long-term contracts as a result of mechanical problems either at the mine or with the transportation delivery system
- The threat or occurrence of a United Mine Workers (UMW) or railroad strike

* There is no clear-cut definition of what constitutes the spot market. Some suppliers consider contracts lasting three or four years "spot" sales, but most limit the definition to arrangements of less than one year.

- Unexpected delays in opening a new mine intended to provide the utility with contract coal
- Uncertainty regarding possible SO₂ emission standards for coal-fired boilers.

Typically, many large coal companies apportion 10 percent to 20 percent of a given mine's reserves to the spot market, because not all coal reserves can be scheduled into long-term contracts and, in any event, there is usually a premium for spot sales. Still, unless there is a prolonged UMW strike or particularly severe weather patterns, spot market purchases generally do not exceed 25 percent of the total market.

The remainder of utility coal is sold under long-term contracts ranging from 5 to 40 years. Contracts for western coal are generally 20 to 30 years; eastern and midwestern coal contracts are typically in the 10- to 15-year range, often with options to renew for 5-year periods. These numbers, however, represent only rough averages. Contract durations are not uniform within regions, states, the same coal company, or the same utility. Some eastern coal contracts run 30 years; some western contracts only 5. For example, within Illinois a survey of all major utilities found that existing long-term contracts ranged from 3 to 25 years.

From a utility perspective, factors which encourage longer term contracts are:

- The basic need to assure a predictable and uninterrupted source of fuel
- The preference to stay with a trusted and proven supplier
- The need to anticipate future coal costs and avoid the premium demanded by spot sales during periods of high demand
- The cost of boiler modifications which might be required to accommodate changes in the type of coal burned.

Some factors arguing for shorter contracts (5 to 10 years) are:

- Uncertainties regarding the suitability of a given coal type should SO₂ or particulate emission limits change
- The preference to keep contracts with new suppliers relatively short until the supplier's reliability has been established

- Limitations on the number of years remaining in the life of specific boilers
- Anticipated favorable fluctuations in the price of coal.

Coal companies, too, are faced with conflicting factors in their choice of contract duration. They may wish to expand rapidly and, hence, prefer longer term contracts to guarantee a steady stream of income in order to pay off increasingly higher new capital investments. On the contrary, new coal technology, government mining regulations, or greater profitability for coal in the future may render 5- or 10-year coal contracts more prudent than long-term obligations, particularly in the case of existing mines.

Consequently, the duration of any particular long-term coal contract is a factor carefully negotiated by both parties. It will depend on a variety of conditions, most of which are site-specific. Still, the "average" contract lengths specified previously are useful since they clearly indicate that existing coal contracts in the utility sector are often long enough (10 years and up) to provide a potential barrier to adoption of PCC.

Commercial/Industrial Sector

The situation in the commercial/industrial sector is quite different. Most of these contracts are for 5 years or less. The reasons for this are primarily the far smaller steam coal requirements of most industrial and commercial users and the greater uncertainty of future coal demand for these businesses. While a medium-sized utility plant contracts for 70,000 to 80,000 tons of coal per month, an average coal-burning industrial facility usually requires no more than 4,000. It is far easier to change suppliers when yearly coal requirements are 50,000 tons than when they are a million tons. Likewise, the variability in utility demand for steam coal is rarely more than ± 10 percent of projected needs; in some industries it is as high as 30 or 40 percent. Consequently, it is more risky for industrial users to become involved in long-term supply contracts.

In many industries (e.g., steel, paper, and cement), "evergreen" contracts are frequently used. These are agreements for 5 or 10 years, but they are renewable annually. Typically, either party can cancel on 30 or 60 days' notice at the end of each year. In most agreements, the

frequently subject to misinterpretation as indicated by the above discussion for the RSD. Skill is required in the selection and use of the appropriate estimators.

The variability of sulfur in a stream of coal from a given mine can be only characterized partially by analyses of raw coal taken, for example on the basis of daily samples. A valid characterization of the variability of sulfur must account for the high correlations that are likely to exist both in space (along a coal seam) and in time (as continuous gaseous emissions from a stack). These correlations, in turn, affect both the precisions of "batch" averages (weekly, monthly, and quarterly averages of daily sulfur measurements), and continuous values obtained from gas monitors. In general, time series and geostatistical methods appear to be well-suited to account for these correlations. Specific geostatistical methods to characterize the variability of sulfur have been explored by Thomas⁽⁴⁻¹⁾. Since data are not available for a detailed geostatistical analysis some preliminary evaluation based on uncorrelated measurements will be made to assess the likely importance of sulfur variability. Consequently, in this report, all statements are taken to be preliminary that pertain to the probability of being out of compliance; the expected proportions of time out of compliance; the average sulfur levels that will yield compliance a stated fraction of the time; the quantitative effect of averaging time on compliance; and the amount of coal from a given region that may be burned in compliance. In addition, all confidence levels, involving the usual 2s or 3s limits, are also provisional.

At best, it can be argued that the use of statistical methods based on uncorrelated measurements primarily serve to indicate qualitative relationships. That is, relative comparisons among the computed results are believed to be qualitatively correct (as greater than or less than). Moreover, the associated quantitative magnitudes, even though not rigorously justifiable, may give reasonable quantitative approximations.

The general effect of sulfur variability and of different averaging times on the average emission level required is shown in Table 13. The values shown are indicative of previous studies conducted for EPA.

The values in Table 13 suggest that short-term averaging requirements may reduce the quantities of raw coal and of cleaned coal which could be

burned in compliance with any given emission limit, because the average sulfur content shown is more than a factor of two lower for a 24-hour averaging period than for long-term averaging.

TABLE 13. SULFUR EMISSION LEVELS REQUIRED FOR SMALL LOT SIZES ACCORDING TO EMISSION STANDARD AND AVERAGING TIME PERIOD

Emission Standard, lb SO ₂ /10 ⁶ Btu	Average Emission Level Required, lb SO ₂ /10 ⁶ Btu		
	Long-Term Averaging	30-Day Averaging*	24-Hour Averaging*
1.2	1.2	0.92	0.58
0.8	0.8	0.62	0.39
0.4	0.4	0.31	0.19

* The relative standard deviation (RSD), defined as $s/\bar{x}$ where s is the standard deviation and $\bar{x}$ is the mean value, is taken as the measure of sulfur variability. A 10 percent RSD is used by the EPA as representative of a 30-day averaging period and a 99.87 percent confidence level is adopted. For a normal distribution, this level occurs at $\bar{x}$ plus 3s. This means that a coal with an average SO₂ emission of $\bar{x}$ will exceed $\bar{x} + 3s$ only 0.13 percent of the time. A 36 percent RSD and a 3s confidence level is used by the EPA as representative of a 24-hour averaging period.

Statistics based on uncorrelated measurements would suggest that the sulfur variability problem is intensified for small industrial boilers because the quantity of coal purchased is smaller. The sizes of the samples to be averaged are smaller and it is then possible that the standard deviation will increase as the boiler size decreases, for any averaging time. However, it should be noted that if correlation were taken into account, as in time series of geostatistical methods⁽⁴⁻¹⁾, this conclusion for small industrial boilers may be found to be incorrect. This approach to sulfur variability is discussed in more detail in the following paragraphs.

Quantifying Variability for Small Lot Sizes and Short Averaging Times

Table 13 is based on an RSD equal to 36 percent for a 24-hour averaging time. This percentage is not based on actual data. Instead, it is based on the assumption of uncorrelated random variables. Such an assumption requires an increased variability for small lot sizes (in comparison with large lot sizes) and/or short averaging times.

It may be assumed that the coal involved in a small lot is mined from the same general location in a seam of coal. Because of this common source, the properties of the coal, including the sulfur content, are assumed to be highly correlated. Because of the high correlation, sulfur emissions over short times would also be highly correlated.

If yesterday's emission was out-of-compliance, today's emission is also likely to be out-of-compliance; conversely, compliance yesterday is likely to indicate compliance today. This predictive ability would be the result of high correlation. The high correlation, in turn, would result from a small lot size mined in the same region. Conversely, if the lot size were increased, the coal properties may be less correlated simply because a larger region of the coal seam is represented by the lot, and consequently the larger lot is likely to be less homogeneous. This would decrease the correlation. In contrast, the statistics of uncorrelated variables shows that an increase in the averaging time may reduce the variability. Arguments based on uncorrelated variables also show that if the mean value is less than the emission limit then large lot sizes may help to insure compliance.

Conclusions and Recommendations on Sulfur Variability Treatment

Although statistical methods which assume the independence of data have been used to interpret the variability characteristics of the sulfur content of coals, evidence is growing that these methods do not lead to proper interpretations. A much more logical approach is provided by the methods of time series analysis or geostatistics, which recognize that sulfur contents of coal data are highly correlatable. The changes in interpretation which will result from the use of these methods will be necessary

to define the true importance of coal sulfur variability. Thus, every effort should be made to continue their development and implementation.

References for Section 4

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SECTION 5

TECHNOLOGY OF PHYSICAL AND CHEMICAL COAL CLEANING

Coal cleaning removes slate, clay, carbonaceous shales, pyrite, and rock aggregate. There are many processes for cleaning coal, each having its own benefits and disadvantages. These processes can be divided into two general categories, physical and chemical coal cleaning. It is the objective of this discussion to present a concise description of physical and chemical coal cleaning processes. Additional information on overall physical coal cleaning costs and benefits is presented in Section 6. Environmental impacts are covered in Section 7.

Physical Coal Cleaning

Physical coal cleaning (PCC) systems that might be employed today range in complexity from simple systems for removing coarse refuse to highly sophisticated systems designed for maximum removal of sulfur and ash from a specific coal supply. The simple systems have been employed widely in the past and may need to be considered from the standpoint of their environmental impacts. They are of little interest, however, for their potential in minimizing the environmental impacts associated with coal combustion. The more sophisticated systems that are designed for maximum removal of sulfur and ash are identified in this section, and feedstock and product characteristics are discussed.

The separation processes that divide the product stream from the refuse fraction are the central components of PCC systems, which perform three operations--coal pretreatment, coal cleaning, and product conditioning. Auxiliary processes are employed for coal handling, water treatment, and solid waste disposal. All operations employ a variety of processes with different potentials for discharging pollutants. Figure 17 schematically displays the processes and operations which are incorporated in PCC systems. The indicated sizes may vary in practice and are shown only as typical size ranges for coarse, fine, and ultra fine coal cleaning circuits.

Three levels of cleaning are effectively practiced:

1. Minimum cleaning effectiveness involves crushing and sizing of raw coal, cleaning the coarse fraction ($3 \times 3/8$ inch) in jigs or dense-medium vessels, and then combining or not combining the uncleaned fine and ultrafine fractions ($3/8$ inch $\times$ 0) with the cleaned coarse fraction. With this level, it is possible to obtain either a high quality coal product or a high Btu recovery, but not both. A high quality coal product may be obtained by use of a low specific gravity of separation (near 1.3) for the coarse fraction and by not combining it with the uncleaned fine and ultrafine fractions. A high Btu recovery may be obtained by use of a high specific gravity of separation (say 1.8) for the coarse fraction and by combining it with the uncleaned fine and ultrafine fractions.
2. For the intermediate level of cleaning effectiveness, the coarse fraction is cleaned as in Level 1, and the combined fine and ultrafine fraction is cleaned with air tables, wet concentrating tables, or dense medium cyclones. Where dense medium cyclones are used, the $3/8$ inch $\times$ 0 feed may be passed over desliming screens which yield a $3/8$ inch $\times$ 200 M material, which is fed to the dense medium cyclones.
3. Maximum effectiveness in cleaning is obtained by cleaning the coarse fraction as in Level 1, splitting the $3/8$ inch $\times$ 0 fraction into two fractions (e.g., $3/8$ inch $\times$ 28 M and 28 M $\times$ 0), and cleaning the two fractions separately with equipment designed for maximum removal of sulfur and ash from fine and ultrafine size coals. The $3/8$ inch $\times$ 28 M fraction is cleaned with wet concentrating tables or dense-medium cyclones. The 28 M $\times$ 0 fraction is cleaned using either hydrocyclones or froth flotation. PCC plants which incorporate processing of the 28 M $\times$ 0 fraction tend to employ thermal drying.

Table 14 illustrates eight basic systems that are commonly employed.

Figure 17 illustrates the processes used for physical coal cleaning. The eighteen processes involved in coal cleaning are described below. The associated numbers relate the process to Figure 17.

TABLE 14. PHYSICAL COAL CLEANING PLANT TYPES^(a)

System	Level of Cleaning Effectiveness	Coal Size and Process		
		Coarse, 3" x 3/8"	Fine, 3/8" x 28 M	Ultrafine, 28 M x 0
1	Minimum	CS+J or DMV	----- None -----	
2	Intermediate	CS+J or DMV	----- AT -----	
3	Intermediate	CS+J or DMV	----- WT -----	
4	Intermediate	CS+J or DMV	----- DMC -----	
5	Maximum	CS+J or DMV	WT	HC+TD
6	Maximum	CS+J or DMV	WT	F+TD
7	Maximum	CS+J or DMV	DMC	HC+TD
8	Maximum	CS+J or DMV	DMC	F+TD

Legend:

CS Crushing and Sizing
 J Jigs
 DMV Dense Medium Vessels
 AT Air Tables
 WT Wet Concentrating Tables
 DMC Dense Medium Cyclones
 HC Hydrocyclones
 TD Thermal Dryers
 F Froth Flotation Units

Note: All wet separation processes will have associated dewatering processes as shown in Figure 17.

- (a) The eight types of coal cleaning plants listed are representative, but many other types exist or may be constructed. For example, in some cases jigs have been used for 3" x 0 coal instead of 3" x 3/8" coal at the minimum cleaning effectiveness levels. The raw coal may be crushed to a finer top size than 3" to maximize impurity liberation. At the maximum cleaning effectiveness level, hydrocyclones and froth flotation units may be used in combination for treatment of fine coal.

Coal Pretreatment Processes

Coal pretreatment processes are employed to generate feed streams with liberated impurities and particle size distributions that have been shown to be most effective for processing in the available coal cleaning processes. Raw coal is crushed to a top size in the neighborhood of 3 inches and screened to provide a coarse stream and a fine-to-ultrafine stream. The latter is either sold, processed directly, or further divided into fine and ultrafine size fractions for wet cleaning. The initial screening of crushed raw coal may be either wet or dry. Dry screening is used if air tables are to be used for coal cleaning. Wet screening is used where fine and ultrafine size streams are processed by wet cleaning processes. The specific processes described here are size reduction, sizing, desliming screen, and ultrafine coal separation.

1. Size Reduction. Raw coal is crushed to sizes suitable for cleaning and shipment to market. The main purpose is to liberate impurities so that they can be removed in the coal cleaning operation.

Size reduction usually involves staged processing in a series of crushers. The extent of the size reduction depends on the type of coal being processed and the desired product characteristics. Raw coal with fines removed is generally fed first to a roll-type crusher (rotary screen-type breakers may be employed for rough cleaning) which reduces it to a top size of 3 to 8 inches. When secondary crushing is used, the coal is reduced to a top size of 1-1/2 to 1-3/4 inches. A third stage, in which crushers further reduce the top size to 1 to 3/8 inch, may be employed. The three-stage layout represents the most economical arrangement for a majority of preparation plants. Between crushing stages, scalping screens are often employed to remove coarse rocks and other foreign materials.

Size reduction of dry coal can be a major source of dust generation. The quantity of dust generated during crushing operations varies depending upon the friability, size, and surface moisture of coal. The more friable coal produces larger percentages of fines. As the coal is crushed to smaller sizes and as moisture decreases, more dust is generated.

Crushing operations are usually carried out in partially enclosed spaces provided with sub-ambient pressure using exhaust hoods and suitable dust collectors such as cyclones, bag filters, and wet scrubbers.

2. Sizing. Sizing is the process of separating particles of mixed sizes into groups in which, for each size fraction, all particles range between certain definite maximum and minimum sizes. There are three general reasons for sizing prior to coal cleaning operations:

1. To separate raw coal into various sizes for marketing,
2. To feed various types of washing units, and
3. To recover fines in the original feed and fines produced by the size reduction process.

3. Desliming Screen. The objective of "desliming" is to remove ultra-fine coal (less than 28 M) which may interfere with fine coal processing and to collect the slimes for direct recovery or separate processing. The size of separation may vary between 28 and 100 M.

Vibrating screens, stationary cross flow screens, sieve bends, Vor-Sivs, etc., are used for slimes removal. Although tonnages vary over a wide range, as an example for a 1000-ton/hr plant, about 300 tons/hr of 3/8-inch x 0 material may exit from wet screening and be input to desliming screens. Streams from these screens in this case could be about 270 tons/hr of cleaned 3/8-inch x 200 M coal and 30 tons/hr of reject material consisting of wet coal and ash less than 200 M.

Wastewater containing the rejected slimes and dissolved impurities associated with the raw coal is generated. This stream is sent to a thickener along with other process waters. The overflow water is recycled or treated and discharged. The underflow slimes generally are reclaimed and processed by froth flotation or hydrocyclones.

4. Ultrafine Coal Separation. Separation of fine raw coal from ultra-fine raw coal permits more efficient isolation of the coal in both streams. The fine fraction is fed to wet concentrating tables, dense medium cyclones, or hydrocyclones, and the ultrafine fraction is fed to hydrocyclones or froth flotation cells.

Sieve bends followed by wet vibrating screens are used to separate the 3/8-inch x 0 material into 3/8-inch x 28 M and 28 M x 0 fractions.

The screening process generates contaminated water, but all process streams are directed to coal cleaning units, and no waste is discharged from the screening step.

Coal Cleaning Processes

A number of approaches have been studied for non-destructive separations of coal from unwanted, associated mineral matter. These include methods based on specific gravity differences, surface properties, and responses to electrical fields or magnetic forces. Almost all methods with demonstrated commercial potential are based on specific gravity differences between the coal and other mineral matter. The only exception is froth flotation where differences in surface properties of coal allow it to be removed from aqueous mixtures of coal and inert minerals with air and organic flotation reagents.

The specific gravities of the principal coal constituents are: organic constituents, 1.2 to 1.7; non-combustible ash (clay, shale, sandstone, etc.), 2.0 to 2.6; and pyrite, 4.9 to 5.0. With differences of this magnitude, methods that separate fractions by specific gravity can be very effective where the components can be isolated from each other in reasonably pure form. Unfortunately, some impurities, pyritic sulfur in particular, are often present in highly disseminated forms that require fine grinding to separate them from the coal. For very fine materials, the effectiveness of separation based on specific gravity decreases because of immobility of particles, particle-to-particle attractions, etc. Hence, froth flotation is finding increased application and other methods for fine coal cleaning are being studied.

The specific processes described here are the use of jigs, dense medium vessels, air tables, wet concentrating tables, dense medium cyclones, hydro-cyclones, and froth flotation.

5. Jigs. Jigs are mechanical devices used for separating materials of different specific gravities by the pulsation of a stream of liquid flowing through a bed of the materials. The liquid pulsates up and down, causing the heavy material to settle to the bottom of the bed and the lighter material to rise to the top. Following the particle stratification, the particle is physically "cut" at any desired particle density plane, thus producing the desired quality products. Jigs are most widely used in coal cleaning. Over 125 million tons of coal are cleaned by jigs annually in the United States.

In coal preparation, jigs are applied to a wide size range of particles with top sizes up to 8 inches and down to zero. With a very wide size range,

however, the efficiency of separation decreases with a decrease in size. Effective separation can be obtained in the size range from 4 to 1/4 inch. Other jig designed utilizing feldspar ragging beds will efficiently clean coal to much smaller sizes (about 48 M). Jigs are simple in operation and require low capital cost; however, their power and water consumption are high. For a 1000-ton/hr plant, the feed stream to jigs could amount to about 690 tons/hr. Outputs then would be about 520 tons/hr of clean coal and 170 tons/hr of refuse.

Waste streams from the jiggling operation are contaminated process water and solid waste. The solid waste is primarily coarse refuse containing waste coal and minerals such as silicates, sulfides, and carbonates associated with the coal seam. The coarse refuse is normally disposed of in waste heaps or embankments by dumping.

The principal pollutant present in process water is suspended solids. A major portion of process water is recirculated through a suitable water clarification circuit. Vibrating screens are usually employed for draining the water from coal larger than 3/8 inch. The drained water may be directly recirculated without further treatment. If the solids concentration is too high, thickeners or settling ponds are used to remove fines. In some instances, treatment with lime is needed to maintain a neutral pH of process water.

6. Dense Medium Vessels. The application of dense medium separation is a practical extension of the laboratory float-sink test. The dense medium used is usually a water suspension containing finely ground magnetite (-325 M) to provide the desired suspension density. Magnetite is used because it can be recovered with magnetic separators. Besides the magnetite, water solutions of calcium chloride and suspensions of sand have been used as dense media. The use of magnetite (5.0 specific gravity) permits practical suspension densities ranging from 1.3 to 2.0 specific gravity. Dense medium vessels for washing coals are three basic types: cones, drums, and troughs.

Dense medium vessels are normally used for cleaning sizes from 6 to 1/6 inch. The benefits of washing material finer than 1/6 inch are usually offset by the increased medium loss and reduced cleaning capacity. Laminar-flow, dense medium separators are efficient on coal coarser than 1/4 inch

and coal recovery is between 95 and 99 percent of the values expected from laboratory float-sink tests. The magnetite used in the dense medium is recycled through a recovery circuit which consists of a sump for collection of the dilute medium, classifying cyclones, a magnetite thickener, and a magnetic separator. About 0.5 pound of magnetite per ton of coal washed is usually lost in the recovery circuit. For a 1000 ton/hr plant, the feed stream and output tonnages for dense medium vessels would be approximately the same as those for jigs (process 5).

The waste streams generated from the dense medium vessels are the same as those from the jigs (see process 5), except that some of the unrecovered magnetite ends up as solid waste. (The remainder of the unrecovered magnetite is part of the clean coal product.)

7. Air Tables. Air tables are somewhat similar to jigs (process 5), except that, instead of water acting as the separating medium, a blast of air is driven through a perforated deck.

Air tables have been used for cleaning 3/8-inch x 0 and 1/4-inch x 0 coal. However, their use has declined because of problems with processing wet coals and the associated dust problems. Close sizing is necessary to obtain good results. Dry cleaning is difficult when surface moisture reaches over 5 percent. For a 1000 ton/hr plant, air tables could process 300 tons/hr of 3/8-inch x 0 material to produce 225 tons/hr of cleaned coal and 75 tons/hr of refuse.

Waste streams from the air tables are dust-laden air and dry solid waste. Dust created by the pulsating air is sucked into an overhead hood and is recovered in a cyclone collector followed by a cloth filter. This dust usually is recovered, as typically it is a rather high-quality product. The dry solid waste can be disposed of by dumping in refuse piles.

8. Wet Concentrating Tables. Tabling is a concentration process whereby a separation between two or more minerals is effected by vibrating a ribbed, tilted surface. The separation depends mainly on the difference in specific gravity and to a lesser degree on the shape and size of the particles.

A normal feed size consistency is about 3/8-inch x 0; but with widespread acceptance of flotation, it is becoming quite common to remove the

minus 48 or 100 M material prior to tabling. Essential factors for good table operation are feed rate, as to volume of both coal and water; slope of the table; and the frequency and amplitude of the stroke. The water-to-solids weight ratio normally used on a table is two to one. About 90 percent of the water reports to the clean coal side of the table. For a 1000-ton/hr plant, the concentrating tables could process 300 tons/hr of wet 3/8-inch x 0 material producing 225 tons/hr of product and 75 tons/hr of wet refuse containing 10 tons/hr of drainable water.

Waste streams generated from wet tabling are contaminated process water and solid waste. The characteristics of the process water are similar to those of the water from jigs (process 5); however, the volume of water from tables is larger, and it contains a higher concentration of suspended solids. The solid waste consists of fine refuse which is normally impounded into a nearby settling pond or disposed of with coarse refuse after dewatering.

9. Dense Medium Cyclones. Dense medium cyclones employ centrifugal forces to accelerate the separation of particles of different specific gravities. In the dense medium cyclone, a mixture of the medium and the raw coal enters tangentially near the top of the cylindrical section thus forming a vortex. The heavy refuse moves along the wall of the cyclone and is discharged through the underflow orifice. The clean coal moves toward the longitudinal axis of the cyclone and passes through the vortex finder to the overflow chamber.

Dense medium cyclones are generally operated at 12 to 14 psi. A medium-to-coal weight ratio of about 5 to 1 is recommended. The dense medium cyclones often have been used to treat a comparatively narrow size range, typically 3/8 or 1/4 inch to 1/2 mm. However, current practice is deviating from this concept. Some units process coals from 1-1/2" to 100 M or even a larger size range. Average loss of magnetite amounts to one pound/ton of feed coal. For a 1000-ton/hr plant, a 270-ton/hr feed stream of wet 3/8-inch x 0 material could be processed by dense medium cyclones to produce 203 tons/hr of clean coal and 67 tons/hr of refuse containing 5 tons/hr of drainable water.

Waste streams from dense medium cyclones are contaminated process water and solid waste. The characteristics of waste streams are similar to those of the wet tables (process 8), except that some lost magnetite ends up in the waste streams. The contaminated water is sent to a thickener. The refuse is dewatered and sent to solid waste disposal.

10. Hydrocyclones. The hydrocyclone does not employ an artificial gravity suspension, but it utilizes an autogenous dense medium developed from the raw coal being cleaned. The specific gravity of separation of a hydrocyclone is regulated by varying the dimensions of the discharge orifices or changing pressure.

Hydrocyclones are used to clean flotation-size coal (-48 M) but can be used for coal as coarse as 1/4 inch to 0. The size classification effect of hydrocyclones is pronounced; therefore, best results can be obtained with narrow-sized feed coal. The hydrocyclone can process large tonnages at relatively low capital investment; however, power and water consumption is high. For a 1000-ton/hr plant, hydrocyclones could process 100 tons/hr of 28 M x 0 material to produce 75 tons/hr of product and 25 tons/hr of refuse.

Waste streams from the hydrocyclones are contaminated process water and solid waste. The characteristics of the waste streams are similar to those from the dense medium cyclones (process 9), except that no magnetite is present. Contaminated water is sent to a thickener. The overflow water is recycled or treated and discharged.

11. Froth Flotation. In froth flotation, separation is effected by the difference in surface characteristics between particles. This process consists of mixing the finely divided coal and mineral suspensions with small amounts of reagents (typically from 0.1 to 1.0 lb of reagent per ton of coal feed) in the presence of water and air. The reagents respond with the particle surfaces and with the water to create conditions conducive to selective attachment of the small air bubbles to the hydrophobic coal particles and carry them to the surface, while the hydrophilic mineral matter is wetted by water and drawn off as tailings. Certain agents in the water modify surface tension to assist in forming air bubbles of proper stability.

Froth flotation is used for both increased recovery and beneficiation of ultrafine coals usually defined as 28 M x 0. The major factors affecting coal flotation are particle size, solids concentration, pH value, and the flotation agents. The optimum size for froth flotation is between 28 and 200 M. For coarser sizes, conventional gravity separation methods are easier and less expensive. Below 200 M, separation efficiency decreases because, for very fine particles, froth flotation becomes increasingly less selective and consumes excessive amounts of reagent due to large total

surface areas. In current coal flotation practice, the solids concentration varies from 3 to 10 percent by weight. As a general rule, the coarser the coal particles, the higher the solids concentration. For a 1000 ton/hr plant using froth flotation, the input and output tonnages would be similar to those for hydrocyclones (process 10).

Waste streams from froth flotation are contaminated process water and solid waste. The characteristics of waste streams are similar to those from the hydrocyclones, except that these contain reagents used in the froth flotation process. However, most reagent remains with coal and refuse. Wastewater is sent to a thickener, and typically the overflow is recycled, but it may be discharged after treatment. Concentrations of reagents released to streams are likely to be very small.

Product Conditioning Processes

The product conditioning processes are primarily for removal of excess water. The processes employed vary with the size of coal being processed. For coarse coal, simple mechanical dewatering which involves the use of natural drainage from perforated bucket elevators or dewatering screens is employed. For finer coal, the surface area is much larger and the amount of moisture retained per unit of surface area is also larger. Tight packing and capillary action tends to hold water in void spaces. Hence, finer coals (less than 1/4 inch) require something more effective than natural drainage.

For coals which contain both medium and fine fractions, e.g., 3/8 inch x 0 or 3/8 inch x 200 M, a sieve bend combined with a centrifuge for additional water removal may be used. For fractions made up exclusively of fine materials (e.g., 28 M x 0) vacuum filtration followed by thermal drying is required.

The specific processes described here are mechanical dewatering, fine plus ultrafine coal dewatering, ultrafine coal dewatering, and thermal drying.

12. Mechanical Dewatering. Following the coarse wet cleaning process (jigs or dense medium vessels), the product coal requires dewatering. Moisture left in the coal decreases the combustion heat available and also causes shipping and handling problems. For coarse coal with particle sizes

greater than 1/4 inch, the coal can be dewatered readily by natural drainage using perforated bucket elevators or dewatering screens. For fine coal, the dewatering is considerably more difficult and costly.

Dewatering methods commonly used for coarse coal are:

1. Drainage Methods. Natural drainage is rapid for coals coarser than 1/2 inch when little or no fine coal is contained therein. Under such conditions, drainage conveyors or perforated bucket elevators can be used to combine dewatering and transferring.
2. Dewatering Screens. Vibrating screens can dewater coal larger than 1/4 inch to the extent required to meet market requirements. Coarse coal may be sized and dewatered on the same screen.

The principal waste stream from mechanical dewatering operations is contaminated water with suspended and dissolved solids containing ultrafine coal and other minerals. This stream typically would be discharged to a thickener, along with other process waters, with the overflow being recycled.

13. Fine Plus Ultrafine Coal Dewatering. Dewatering of coal which contains slimes (less than 28 M) requires a greater driving force for water removal than is obtained with simple mechanical dewatering even if a substantial amount of coarse material is present. Product streams requiring such dewatering are generated by wet cleaning of 3/8-inch x 0 or 3/8-inch x 200 M material with wet concentrating tables or dense medium cyclones.

Dewatering of products containing both fine and ultrafine coal is accomplished with a variety of profile wire dewatering screens in series with centrifuges. A 1000-ton/hr plant would produce around 225 tons/hr of cleaned 3/8-inch x 0 material if concentrating tables are used or 200 tons/hr of 3/8-inch x 200 M material when deslimed material is processed in dense medium cyclones.

The main waste stream is contaminated water which is similar to that produced by mechanical dewatering. Because the coal is much finer, the loadings of both dissolved and suspended solids may be higher. This stream is sent to a thickener and the overflow water is recycled or treated and recycled.

14. Ultrafine Coal Dewatering. Wet ultrafine coal (28 M x 0) is beneficiated by hydrocyclones and froth flotation. This very fine material has high surface area and has a tendency to pack tightly so that dewatering is not sufficiently effective.

Ultrafine coal streams are dewatered using solid bowl centrifuges and vacuum filters. For a 1000-ton/hr plant, about 75 tons/hr of fine material could be processed with about 5 tons/hr of contaminated water removed. The dewatered product may be sent to thermal dryers or blended with larger-size clean coal products with lower moisture content.

The vacuum filter produces contaminated water that would be the same as that produced by mechanical methods except that it will contain flocculation agents. However, most agents remain with the coal and refuse. This stream is sent to a thickener along with other waste waters; typically, the overflow is recycled, but it may be discharged after treatment. Concentration of agents released to streams is likely to be very small.

15. Thermal Drying. Thermal drying is a process of accelerated evaporation where wet coal and hot gases are brought into intimate contact with each other. The hot gases are usually the gaseous combustion effluent from a coal burner but excess "tempering" air is added to the off-gas to control inlet dryer gas temperature to achieve the optimum range for coal drying. After loading, the thermally dried coal must be kept below its critical ignition temperature of 130 to 150 F to prevent spontaneous combustion. Other important aspects in product coal temperature control are oxidation and devolatilization which will adversely affect coal quality if not controlled.

Thermal dryers used in coal preparation can be grouped into six basic types:

1. Rotary Dryers. The rotary-type dryer consists of cylindrical drums in which the wet coal travels slowly from the feed to the discharge end. The hot combustion gases usually travel in the reverse direction in intimate contact with the coal.
2. Screen-Type Dryers. Screen-type dryers carry the coal on reciprocating screens which promote evaporation by passing hot gases through the bed. The gas flow is usually alternated so as to transfer the suction from one screen to the other section.

3. Multi-Louver Dryers. In the multi-louver dryer, the coal falls in a thin stream over the face of the ascending louver, and hot gases are passed between the filled louvers and through the layers of solids descending in free fall.
4. Cascade Dryers. Cascade dryers accomplish their heat transfer by introducing hot gases through and between the wedge-wire shelves which are arranged to cause the coal to cascade. The coal forms a curtain of flowing coal, and hot gases are passed through it to impart heat for evaporation.
5. Suspension-Type Dryers. Suspension-type dryers introduce the wet coal into a moving stream of hot gases which pneumatically convey and dry the material in transit. Cyclone collectors separate the coal from the moisture-laden spent gases.
6. Fluidized-Bed Dryers. In fluidized-bed dryers, the wet coal is fed into a perforated or bar-type retention plate where hot gases are blown or drawn through the bed. Fluidized beds are characterized by a loose pulsating mass which is made to act as a liquid by the gas stream. Fluidized bed dryers are the most commonly used in coal cleaning plants. For a 1000-ton/hr plant, thermal dryers could process 220 tons/hr of dewatered coal from the medium and fine coal cleaning circuits.

In addition to these six types of thermal dryers, there are new dryer designs which carry the heat by means other than hot gases to minimize dust control problems.

Thermal dryers are the largest single source of air pollution in coal cleaning plants. In thermal drying, uncontrolled emissions of particulate matter may be in the range of 15 to 25 pounds per ton of thermally dried coal. Thermal dryers also generate gaseous pollutants including sulfur dioxide, nitrogen oxides, carbon monoxide, and hydrocarbons. These emissions are variable depending on the coal used for combustion and the type of dryer.

Emissions from thermal dryers are universally controlled by cyclones and wet scrubbers. Cyclones are integral parts of thermal dryers and are used for recovery of fine coal particles. Venturi scrubbers are commonly employed as secondary collectors. A consequence of wet scrubbing is the

generation of contaminated scrubber water, which is usually sent to thickeners or settling ponds for clarification, after which chemical treatment commonly is required prior to plant recirculation.

Coal-fired thermal dryers produce ash from combustion which must be disposed of as solid waste.

Auxiliary Processes

Auxiliary processes, i.e., processes that are in some way incidental to the main functions involved in PCC but are still of great importance to plant operation, are coal handling and storage, water handling, and solid waste disposal.

16. Coal Handling and Storage. In conjunction with transportation and storage of coal, a wide variety of material handling operations is needed. These include unloading, stacking and reclaiming, and transferring coal in a plant. As the amounts of coal to be handled have grown, the material handling systems have become more mechanized and equipped with more automatic and integrated control devices.

Storage of coal is an economic necessity in coal preparation to provide a reserve against production interruptions and also to facilitate intermittent shipment. Coal is stored in huge open piles or enclosed bins and silos.

Coal handling systems which relate to coal transportation are loading and unloading facilities. The facilities required for coal loading and unloading are different depending on the modes of transportation.

Coal storage can be divided into two categories according to purpose: active storage, which supplies processing directly, and reserve storage to guard against delays in shipments.

Active coal storage is generally in a covered structure such as a bin, silo, or bunker, depending on the storage capacity required. Reserve coal storage is usually in outdoor piles. Storage areas should be well drained and raised to be protected from flooding. Drainage ditches should be installed alongside the pile. Coal piles are constructed with the steepest slopes possible to prevent rain or melting snow from penetrating into the pile.

Stacking, reclaiming stored coal, and movement of coal between processing units involves the use of various types of equipment ranging from belt and bucket conveyors to bulldozers. The type of equipment used for coal handling will depend on plant specific variables such as plant capacity, storage capacity requirements, and configuration of available land.

Waste streams from the storage of coal are fugitive coal dust and precipitation runoff or leachate. The amount of dust generated from the open storage piles varies widely depending on climate, topography, and characteristics of the stored coal. The generation of dust may occur at any transfer point; control is critical at such locations. Outdoor piles have large surface areas and rainwater has a chance to react with pyrite and other mineral matter to form acids and to extract soluble metal ions, resulting in acid water drainage. The area around preparation plants should be properly designed with diversion and drainage ways through proper slopes and collection sumps. These waters must be collected for treatment and not be permitted to escape to the environment.

Dust control methods for open storage include spraying with water or surfactants; dust-proofing by creating the surface with oil or calcium chloride; and providing wind screens. Runoff from storage areas should be collected and sent to a retention pond (to settle out solids) or to a water treatment facility. Lime can be used in either case to neutralize acidity.

The principal waste stream from coal handling is fugitive coal dust. Long, open conveyor belts carrying dry coal can be a significant source of dust and all drop points onto or off conveyors are sources of dust emissions. Fugitive dust can be suppressed by water spraying and dust proofing. Float dust from loading operations can be minimized by use of a telescoping chute.

17. Water Handling. Coal washing operations require large amounts of water. In 1962, coal cleaning plants in the U.S. used over 170 billion gallons of water which included 81 percent recirculated water and 19 percent fresh water. Water handling in coal cleaning plants can be divided into two main areas: (1) obtaining a reliable source of fresh water for utilization in the coal cleaning operations, and (2) treating waste water from the plant so that it can be recirculated or discharged without presenting water pollution problems.

Possible sources of fresh water are municipal water, deep wells, man-made lakes, nearby streams, and mine water. It is desirable for plant usage that the process water contain less than 5 percent suspended solids for most purposes. However, for rinse water these levels are generally unacceptably high. Pump gland water should be essentially free of suspended solids and of high quality. Process water should have a near neutral pH and low conductivity, i.e., low dissolved solids. Although low conductivity water is desirable, it is seldom attained due to the presence of varying levels of soluble components in the ROM (run of mine) coal. Technology to remove dissolved solids from process water is available, but acceptably costly for coal preparation systems.

As a result of stream pollution regulations and the coal industry's desire to improve fine coal recovery, recirculation and treatment of wash water are integral parts of the operation of a modern coal cleaning plant. In particular, closed water circuits have grown in popularity because they eliminate discharge to streams, reduce makeup water, and allow for recovery of coal. Since closing the circuit results in the buildup of slimes, it is necessary to remove a certain portion of these fine solids. Standard equipment generally applied in a closed water circuit consists of thickeners, cyclones, filters, and/or solid bowl centrifuge.

The major waste stream from water handling operation is the solid waste generated from water clarification. Since the solid waste consists of extremely fine size materials and considerable amounts of water, the disposal of it requires special care. Water pollution problems may be encountered from acid water drainage and dust may be generated if the waste is completely dried. In addition, accidental overflow of settling ponds may create serious water pollution.

Waste streams from plant cleanup (wash down) are also significant. Coal preparation plants should be frequently washed down with fresh water to remove solids from accidental spills and settled dust, etc. These waters and solids are collected in plant sumps and combined with slime streams for solids removal and water recycle.

18. Solid Waste Disposal. The disposal of coal cleaning plant waste is a worldwide problem of increasing magnitude. Coal refuse consists of waste coal, slate, carbonaceous and pyritic shales, and clay and rock

associated with a coal seam. It is estimated that about 25 percent of the raw coal mined is disposed of as waste. This enormous quantity of refuse varies considerably in physical and chemical characteristics depending on the coal source and the nature of the preparation process.

The disposal of coal refuse involves two quite separate and distinct materials--a coarse to fine refuse (+28 M) and an ultrafine refuse (-28 M). Coarse to fine refuse is transported to the disposal area by a variety of material handling systems, which include aerial trams, conveyors, trucks, side-dump mine cars, scrapers, and bulldozers. In mountain regions, the types of disposal used include cross-valley fill, valley-fill dump, and side-hill dump.

In flat land, the refuse is simply deposited in waste heaps, usually ending up in the general shape of a truncated cone. Active and abandoned strip mines can be used for the disposal of both slurry refuse and coarse refuse from preparation plants. Layering, compaction, and revegetation may be used to reclaim the disposal area.

Disposal of ultrafine refuse may be by slurry impoundment, underground disposal, and disposal after dewatering. Transportation by pipeline may be employed before disposal.

Solid waste is the largest single source of potential pollution from coal preparation. Adverse effects associated with coal refuse disposal include air pollution, water pollution, land pollution, safety hazards, and ecological and psychological impacts. Fugitive dust can pollute the air and leachate can pollute surface or underground water. Methods for fugitive dust control and leachate collection and treatment discussed for coal storage, as part of the description of process 16, are applicable to solid waste also.

Burning refuse piles can be especially troublesome sources of air pollution. In 1968, the U.S. Bureau of Mines conducted a survey to locate and examine coal refuse piles in 26 coal-producing states. At that time, they located 292 burning piles in 13 states. Of these, at least 66 were believed to be spontaneously ignited by air flowing through the pile. (5-1)

There are several ways of controlling coal refuse pile fires such as digging out and cooling the affected material, covering up and sealing the pile against air circulation, and grouting to solidify the affected

material; however, the most effective way to control coal refuse fires is to prevent them. Important measures stressed for coal refuse pile fires include locating refuse piles a safe distance from active mining operations and facilities and from abandoned mine openings; cleaning vegetation from the disposal site; compacting every 2-foot layer of refuse; and sealing the open slopes with clay or other inert materials to prevent air circulation. Current Federal regulations, if followed, should end fires in new coal refuse piles.

Costs of Physical Coal Cleaning

A number of factors can affect the cost of producing electricity or steam from coal while meeting environmental standards. The use of physical coal cleaning (PCC) can have a beneficial impact on many of these factors. The use of PCC as an emission control strategy provides a number of potential cost savings which may more than offset the cost of PCC in many cases.

In this section, the elements of PCC costs are described, and costs for several typical PCC plants are summarized.

Physical Coal Cleaning Cost Factors

The cost of PCC is heavily dependent upon the characteristics of the raw coal, the level of cleaning for which the cleaning plant is designed, and the plant capacity. Total cost of PCC includes capital charges, operating and maintenance (O&M) costs, and the cost of the Btu loss due to material discarded as refuse, sometimes called coal replacement cost.

Only the PCC costs to the coal cleaning plant operator are considered here. The cost of clean coal to an end user, if purchased from a coal cleaning plant operator, depends on the operator's selling price for clean coal, which is dependent on such additional factors as raw coal cost, selling costs, general and administrative expenses, income tax rates, and profit margins.

Capital investment costs for PCC facilities typically include, but may not be limited to, the following factors:

- Engineering design
- Construction of buildings and auxiliary facilities
- Interest during construction
- Site development
- Equipment, piping, and instrumentation
- Installation
- Outside lines
- Start-up costs.

Other capital investment costs typically include land and working capital which, although generally a small percentage of total capital investment, in a detailed accounting of PCC costs should not be depreciated over the useful life of the plant because of their residual value.

O&M costs for PCC typically include, but may not be limited to, the following factors:

- Raw materials and supplies
- Utilities (electricity, water, etc.)
- Labor and overhead for coal handling, plant operation and maintenance, pollution control, and refuse disposal
- Payments to union welfare fund.

Other related costs which may be treated as operating costs include insurance, payroll taxes, and property taxes.

The capital investment* for a PCC facility may range approximately from \$6,600⁽⁵⁻²⁾ to \$42,000⁽⁵⁻³⁾ per ton/hour of feed coal capacity, depending on its complexity and size. The lower cost is for a simple jig plant processing 6 in. x 0 raw coal with the 48 M x 0 fraction processed by hydrocyclones to produce a 48 M x 120 M clean coal fraction. The higher capital investment figure is for the multistream coal cleaning system (MCCS) at Homer City, Pennsylvania.

O&M costs* for PCC may range approximately from \$0.06⁽⁵⁻⁴⁾ to \$4.00⁽⁵⁻⁵⁾ per ton of feed coal. The lower figure is for coarse beneficiation, i.e., washing of +3/8-inch material only with the 3/8-inch x 0 fraction being shipped dry as is. The higher figure applies to full beneficiation of a coal with large amounts of -28 M material (above 20 percent) using heavy medium circuits and full treatment of the fines.

* 1977 dollars.

Factors affecting capital costs include coal characteristics, plant capacity, types of processes, degree of cleaning, degree of automation, pollution control techniques, location, facilities for coal handling and storage, and solid waste disposal facilities. O&M costs are also affected by these factors and, in addition, by plant utilization, payroll and property taxes, insurance, and operator experience.

The overall cost of coal preparation may be expressed in units such as \$/ton of clean coal, \$/ton of raw coal, $\$/10^6$ Btu, or \$/lb of sulfur removed. To obtain such overall costs, capital investment costs usually are converted to fixed annual charges on capital, by making appropriate estimates for the useful plant life, L , of the facility (in years) and the interest or discount rate, i , (annual percentage). The values of L and i determine the capital recovery factor (CRF) which is multiplied times the capital investment cost to obtain the fixed annual charges on capital. Such charges allow for amortization of the capital investment over the useful life of the physical asset.

When the fixed annual charges on capital are converted to \$/ton or $\$/10^6$ Btu, it is clear that the plant utilization directly affects the result. As an example, with a useful plant life of 15 years and a discount rate of 12 percent, the capital recovery factor is 0.14682. With a plant capacity of 1000 tons/hour and a plant utilization of 42 percent, or 3690 hours/year, the capital investment cost range of \$6,600 to \$42,000 per ton/hour of capacity converts to a range for charges on capital of \$0.26 to \$1.67/ton of feed coal. Adding these capital charges to O&M costs results in an approximate total cost range of \$0.86 to \$5.67/ton of feed coal for PCC, not including the cost of material discarded as refuse. Cost per ton of clean coal is obtained by dividing by weight yield, Y ; e.g., if $Y = 0.8$, then the above approximate total cost range becomes \$1.08 to \$7.09/ton of clean coal.

The calculated value of fixed annual charges on capital is very sensitive to the estimated useful plant life and discount rate. Both the capital and O&M costs per ton of feed or clean coal are very sensitive to the estimated plant utilization. Thus, the cost ranges given above are subject to significant variations as estimates for these parameters differ from the representative values used here.

Another cost which must be considered is due to the Btu loss in the material discarded as refuse in the PCC process. The operator of a PCC plant

uses a certain amount of raw material (feed coal) to produce a smaller amount of product (clean coal). When coal is bought and sold on a dollars per ton basis, the cost of the feed coal in \$/ton must be prorated over the clean coal tonnage to determine the cost of "raw materials" per ton of product. This is done by dividing the cost of feed coal, in \$/ton, by the weight yield. For example, with a \$20/ton cost of feed coal and an 80 percent weight yield, the cost of "raw materials" per ton of clean coal is \$25.00. This difference of \$5.00 per ton is attributable partially to the Btu's lost in the refuse and partially to the increase in heating value achieved for the clean coal.

It is important to recognize that, although the cost of material discarded as refuse must be considered in determining the cost of the clean coal product to the PCC plant operator, the removal of undesirable constituents, such as pyrite, ash, and certain trace elements contained in the refuse, is the purpose of coal cleaning and makes the product more valuable on a per ton basis. Because the undesirable constituents removed by PCC have relatively low heating values, the clean coal product has a higher heating value than the feed coal. A distinction needs to be made between cost and value of Btu's. The cost of Btu loss calculated in this section is based on assigning an equal cost to each Btu by dividing the cost of feed coal in \$/ton by the heating value of the feed coal in 10^6 Btu/ton. However, to the end user of cleaned coal, the Btu's associated with the discarded material are not as desirable, or valuable, as the Btu's associated with the clean coal product. Removal of ash, sulfur, and other low-heating value constituents of coal results in economic benefits to an end user of clean coal. Such benefits to a power plant operator include reduction of costs for ash disposal, coal transportation, and plant maintenance and increases in plant peaking capacity, rated capacity, and availability. According to a recent study, power plants can expect to experience operating and maintenance incremental costs increased due to poor quality coal starting at about \$1.00/ton for coal containing 13 percent minerals (ash plus sulfur) and ranging to about \$8.00/ton for coal containing 25 percent minerals. ⁽⁵⁻⁶⁾ The use of cleaned coal can result in a major reduction of such costs. Other economic benefits from using cleaned coal can result from reduced requirements and costs for flue gas desulfurization as discussed in Section 6.

The cost of Btu loss may be illustrated using the example defined in Figure 18. For feed coal with a heating value of 12,000 Btu/lb, the total

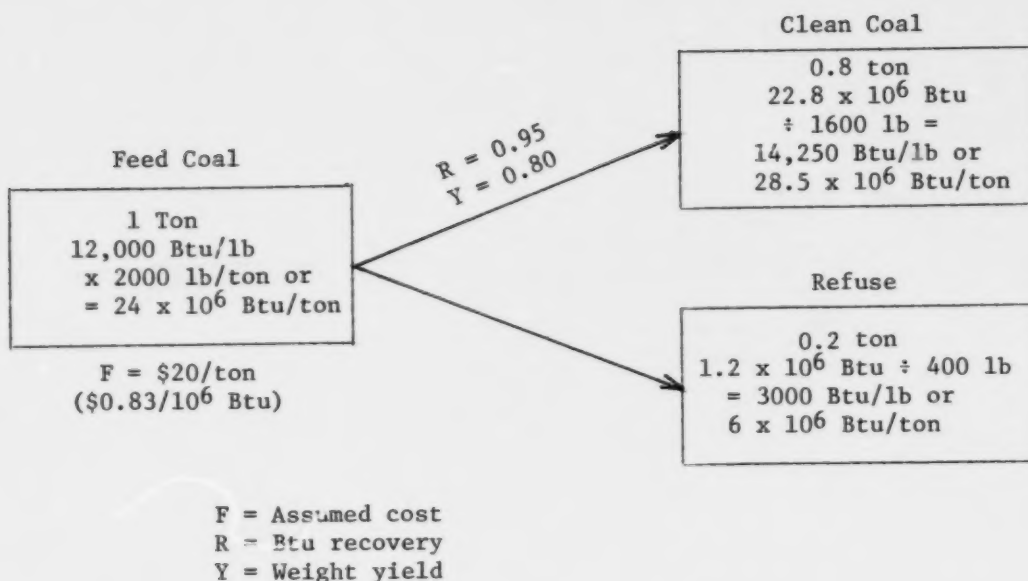


FIGURE 18. EXAMPLE ILLUSTRATING RELATIONSHIPS INVOLVED IN DETERMINING COST OF DISCARDED MATERIAL

heating value for 1 ton is 24×10^6 Btu. The assumed cost, F, of \$20/ton is equivalent to $\$0.83/10^6$ Btu. With a Btu recovery, R, of 0.95 and a weight yield, Y, of 0.80, 0.8 ton of clean coal is produced with a total heating value of 22.8×10^6 Btu which is 14,250 Btu/lb or 28.5×10^6 Btu/ton.

If the cost of the feed coal is prorated on a heating value basis, the cost, C, of the Btu loss, in $\$/10^6$ Btu in clean coal, is found by first obtaining FT_F , the cost of Btu's in the feed coal ($\$20/\text{ton} \times 1 \text{ ton} = \$20$) and multiplying this result by $1-R$ (0.05) to obtain the cost of Btu's in the refuse (\$1). This result is divided by $H_F T_F R$, the Btu's in the clean coal (22.8×10^6 Btu), to obtain C, the cost of Btu loss ($\$0.0439/10^6$ Btu in clean coal). These steps may be written as

$$C = \frac{FT_F (1-R)}{H_F T_F R} \quad (1)$$

where C = cost of Btu loss, $\$/10^6$ Btu in clean coal
 F = cost of feed coal, $\$/\text{ton}$
 T_F = tons of feed coal
 R = Btu recovery, percent/100
 H_F = heating value of feed coal, 10^6 Btu/ton.

Equation (1) reduces to the following simplified general equation for determining the cost of Btu loss per 10^6 Btu in clean coal.

$$C = \frac{F (1-R)}{H_F R} \quad (2)$$

The costs of Btu loss to the PCC plant operator, per 10^6 Btu in the clean coal, for various coal feed costs, F, and Btu recoveries, R, and for $H_F = 24 \times 10^6$ Btu/ton, were obtained by Equation (2) and are shown in Table 15.

TABLE 15. COST OF BTU LOSS FOR $H_F = 24 \times 10^6$ BTU/TON, $\$/10^6$ BTU IN CLEAN COAL

F, Cost of Feed Coal, \$/ton	100 R, Btu Recovery, percent			
	80	85	90	95
10	0.1042	0.0735	0.0463	0.0219
15	0.1563	0.1103	0.0694	0.0329
20	0.2083	0.1471	0.0926	0.0439
25	0.2604	0.1838	0.1157	0.0548

The costs of Btu loss may also be obtained in $\$/\text{ton}$ of clean coal by first multiplying $1-R$ (0.05) times the tons, T_F , of feed coal (1 ton) times the heating value, H_F , of feed coal (24×10^6 Btu/ton) to obtain the Btu's in the refuse (1.2×10^6 Btu/ton). This result is then multiplied by the cost, F/H_F , of the Btu's in the raw coal ($\$0.83/10^6$ Btu) to obtain the cost

of raw materials in the refuse (\$1.00) which is then divided by tons of clean coal, Y (0.8) times T_F (1 ton), to obtain the cost of Btu loss (\$1.25/ton of clean coal). These steps may be written as

$$C' = \frac{(1-R) T_F H_F (F/H_F)}{T_F Y} \quad (3)$$

where C' = cost of Btu loss, \$/ton of clean coal

Y = weight yield, percent/100

R , T_F , H_F and F are as defined for Equation (2).

Equation (3) reduces to the following simplified general equation for determining the cost of Btu loss per ton of clean coal.

$$C' = \frac{(1-R) F}{Y} \quad (4)$$

The costs of Btu loss per ton of clean coal for various coal feed costs, F , the weight yields, Y , and for $R = 0.95$, were obtained by Equation (4) and are shown in Table 16.

TABLE 16. COST OF BTU LOSS FOR $R = 0.95$,
\$/TON OF CLEAN COAL

F, Cost of Feed Coal, \$/ton	100 Y, Weight Yield, percent				
	60	70	80	90	95
10	0.83	0.71	0.63	0.56	0.53
15	1.25	1.07	0.94	0.83	0.79
20	1.67	1.43	1.25	1.11	1.05
25	2.08	1.79	1.56	1.39	1.32

Tables 15 and 16 can be shown to be consistent for the example in Figure 18 by multiplying the costs in $\$/10^6$ Btu for $R = 0.95$ in Table 15 times the heating value of the clean coal, 28.5×10^6 Btu/ton, to obtain the costs in \$/ton for $Y = 0.80$ in Table 17.

It is noted that the cost of Btu loss in \$/ton of clean coal plus feed coal cost/ton does not fully account for the cost of "raw materials" per ton of clean coal. In the example in Figure 18, the cost of "raw materials" per ton of clean coal is \$25.00, but the cost of feed coal is \$20.00 per ton and the cost of Btu loss is only \$1.25/ton of clean coal. The other \$3.75 per ton of clean coal is attributable to the higher heating value of the clean coal and the prorating of feed coal costs on the basis of heating value. In general, the increase in cost per ton of clean coal over the cost per ton of feed coal, due to both Btu loss and increased heating value, is found by first multiplying F (\$20/ton) times T_F (1 ton) to obtain the total cost of feed coal. This result (\$20) is then divided by $Y T_F$ (0.95×1 ton), the number of tons of clean coal, to obtain the "raw materials" cost of clean coal (\$25/ton). From this result, the cost of feed coal, F (\$20/ton), is subtracted to obtain the increase in cost per ton of clean coal over the cost per ton of feed coal, due to both Btu loss and increased heating value. These steps may be written as

$$\Delta = \frac{F T_F}{Y T_F} - F \quad (5)$$

or

$$\Delta = \frac{F}{Y} - F = F \left(\frac{1-Y}{Y} \right) \quad (6)$$

where Δ = increase in cost of clean coal over the cost of raw coal, \$/ton.

Equation (6) was used to determine Δ for various feed coal costs, F , and weight yields, Y , and the results are shown in Table 17.

TABLE 17. INCREASE IN COST OF CLEAN COAL OVER COST OF FEED COAL DUE TO BOTH BTU LOSS AND INCREASED HEATING VALUE, Δ IN \$/TON OF CLEAN COAL

F, Cost of Feed Coal, \$/ton	100 Y, Weight Yield, percent				
	60	70	80	90	95
10	6.67	4.29	2.50	1.11	0.53
15	10.00	6.43	3.75	1.67	0.79
20	13.33	8.57	5.00	2.22	1.05
25	16.67	10.71	6.25	2.78	1.32

The difference between corresponding costs in Tables 16 and 17 represents $\Delta-C'$, or the increase in cost per ton of clean coal over the cost per ton of feed coal attributable to increased heating value of the clean coal.

Although PCC costs depend on site-specific factors, approximate cost ranges previously discussed may be summarized as in Table 18.

TABLE 18. APPROXIMATE RANGES OF PCC COSTS

Cost Category	Approximate Cost Range, \$/ton of clean coal
Capital Charges	0.44 - 2.79
O&M	0.75 - 5.00
Btu Loss	0.53 - 2.08
Total	1.72 - 9.87

This approximate range of PCC costs is comparable to the approximate range of cost penalties, \$1.00 to \$8.00/ton, which Phillips and Cole⁽⁵⁻⁶⁾ estimate a power plant incurs by burning poor quality coal ranging from 13 to 25 percent minerals. In some cases, PCC costs may be more than offset by power plant cost reductions resulting from the use of cleaned coal. Additional economic benefits from use of clean coal can result from reduced flue gas desulfurization requirements and costs, as discussed in Section 6.

Case Studies of PCC Costs

A recent report⁽⁵⁻²⁾, based on a study by the Hoffman-Muntner Corporation, presents the results of detailed case studies of the costs of eight PCC plants. These plants represent a spectrum of PCC technology from a relatively simple jig process to relatively complex circuits involving heavy medium cyclones, froth flotation cells, and thermal dryers. The results of these case studies are summarized briefly here.

The eight coal preparation plants listed in Table 19 are described in the Hoffman-Muntner study⁽⁵⁻²⁾ as representative of typical configurations and capacities currently in use. Preparation plant facilities were grouped into three categories: (1) raw coal storage and handling, (2) preparation plant, and (3) other facilities and equipment. The first category includes storage areas and silos, conveyor belts, tramp iron magnets, crushers, breakers, and screens, all for raw coal.

The preparation plant category includes screens, crushers, Baum jigs, classifying cyclones, hydrocyclones, concentrating tables, sieve bends, heavy medium vessels and cyclones, froth flotation cells, vacuum filters, magnetic separators, centrifugal dryers, sumps, pumps, and other PCC process equipment. The total preparation plant equipment cost was multiplied by a factor of 3 to obtain a total preparation plant cost including site preparation, construction, electrical service, piping, etc.

The third category includes thermal dryers, thickeners, coal sampling systems, clean coal loading facilities, and the following facilities or equipment for clean coal and refuse: storage areas and silos, conveyor belts, and handling equipment. A contingency of 15 percent, to allow for interest during construction and other factors, was added to the sum of capital costs in the three categories to obtain the total estimated capital investment cost for each plant.

The estimated capital cost for each of these eight plants is reported in Table 20. In general, the estimated capital charges (in dollars per ton/hr of capacity) of heavy-medium plants are higher than those for jig processes.

The total annualized costs, which include operating and maintenance cost, capital charges, and cost of Btu loss are shown in Table 21. Capital charges are based on an interest (discount) rate of 9 percent, a ten-year plant life, and 30 percent plant utilization. The operating and maintenance cost includes labor, supervision, overhead, supplies, fuel, electricity, and subcontract services.

Although plant 8 is a complex heavy-medium system, its utilization is approximately 50 percent, and this reduces the total annualized cost burden. Two parallel circuits are operated at full capacity for two shifts per day; one of the circuits is then operated for a third shift with the second circuit

TABLE 19. DESCRIPTION OF COAL PREPARATION PLANTS (5-2)

Plant No.	Type of Process	Raw Coal Capacity (TPH) (a)	Complexity	Btu Recovery, %	Weight Yield, %	Moisture Content in Clean Coal, %	Heating Value of Clean Coal, Btu/lb (Moisture Free)	Total Sulfur Content in Raw Coal, %	Ash Removal, (b) lb/T	Sulfur Removal, (b) lb/T
1	Jig	600	Simple	91.6	59.0	8 - 9	13,236	0.65	651	3.7
2	Jig	1,000	Intermediate	96.4	71.4	6.9	12,974	3.42	472	23.3
3	Jig	1,000	Intermediate	83.0	56.6	4.6	13,056	4.30 (3.01)	606	27.7
4	Jig	1,600	Complex	93.7	59.6	5.8	14,244	1.0	678	9.0
5	Heavy Medium	1,400(720) (c)	Simple	94.6	74.0	7.5	10,992	4.56	260	29.5
6	Heavy Medium	600	Complex	89.2	73.3	5.0	14,336	4.38	338	55.2
7	Heavy Medium	600	Complex	93.1	60.0	4.9	13,348	1.0	660	6.3
8	Heavy Medium	900	Complex	94.3	86.0	5.0	13,130	2.45	145	18.0

(a) TPH = tons per hour.

(b) lb removed/ton of raw coal processed.

(c) 680 tph of raw coal is not processed by the cleaning plant.

TABLE 20. SUMMARY OF ESTIMATED TOTAL CAPITAL REQUIREMENTS FOR
EIGHT COAL PREPARATION PLANTS⁽⁵⁻²⁾
(Mid-1977 Dollars)

Plant No.	Raw Coal Storage & Handling, (\$ x 10 ³)	Preparation Plant, (\$ x 10 ³)	Other Facilities, (\$ x 10 ³)	Contingency, (\$ x 10 ³)	(a)	Total Capital Cost, (\$ x 10 ³)	Capital Charge, \$/TPH ^(b)
1	424	1,543	1,464	515		3,946	6,600
2	1,418	3,762	6,716	1,785		13,681	13,700
3	1,080	4,342	5,086	1,576		12,084	12,100
4	1,560	9,530	8,811	2,985		22,886	14,300
5	2,412	2,744	3,506	1,300		9,962	13,800 ^(c)
6	1,019	4,238	6,437	1,754		13,449	22,400
7	684	3,347	3,290	1,098		8,420	14,000
8	1,190	7,850	9,148	2,728		20,916	23,200

(a) Contingency equals 15 percent of sum of raw coal storage and handling, preparation plant, and other facilities.

(b) TPH: tons per hour.

(c) Based on 720 TPH which is being cleaned; not 1,400 TPH input to plant.

TABLE 21. TOTAL ANNUALIZED COSTS FOR EIGHT COAL PREPARATION PLANTS (5-2)
(Mid-1977 Dollars)

Plant No.	Operating and Maintenance Cost (a)		Capital Charges (b)		Cost of Btu Loss		S/Ton of Raw Coal		S/Ton of Clean Coal		S/Ton of Raw Coal		S/Ton of Clean Coal		S/10 ⁶ Btu Recovered		S/Ton of Ash Removed		S/Ton of Sulfur Removed	
	S/Ton of		S/Ton of		S/Ton of		S/Ton of		S/Ton of		S/Ton of		S/Ton of		S/10 ⁶ Btu Recovered		S/Ton of		S/Ton of	
	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal	Raw Coal	Clean Coal
1	1.59	2.70	0.38	0.65	1.26	2.14	3.23	5.49	3.16	4.42	0.227	0.183	9.92	13.39	0.227	0.183	9.92	13.39	1.746	271
2	1.82	2.55	0.80	1.12	0.54	0.75	4.76	8.43	4.76	8.43	0.338	0.222	15.71	10.47	0.338	0.222	15.71	10.47	344	789
3	1.51	2.67	0.71	1.25	2.54	4.49	3.55	5.96	3.55	5.96	0.239	0.239	27.69	30.53	0.239	0.239	27.69	30.53	244	187
4	1.76	2.96	0.84	1.40	0.95	1.60	3.60	4.86	3.60	4.86	0.258	0.206	9.55	52.28	0.258	0.206	9.55	52.28	1,000	421
5(c)	2.37	3.20	0.42	0.56	0.81	1.10	5.16	7.04	5.16	7.04	0.206	0.176	4.40		0.206	0.176	4.40			
6	2.23	3.04	1.31	1.79	1.62	2.21	3.15	3.79	3.15	3.79										
7	1.27	2.12	0.82	1.36	1.06	1.76														
8	2.10	2.44	0.81(d)	0.94(d)	0.88	1.02														

(a) Includes labor, supervision, overhead, supplies, fuel, electricity, and subcontract services.

(b) Based on a 10-year amortization period, 9 percent discount rate, and 30 percent utilization factor, except as noted.

(c) Costs shown for Plant No. 5 are based on 1,400 TPD.

(d) Fifty percent utilization factor.

down for maintenance. Although the capital costs are higher due to the duplication in facilities, operating time and, therefore, plant throughput are increased by this method.

The figures reported in the last two columns in Table 21 for cost of ash and sulfur removal illustrate the dependency of the plant efficiency on site specific conditions such as coal size and composition. A wide range exists for the cost of ash and sulfur removal.

Table 21 includes capital charges and operating and maintenance costs for water treatment but not for air pollution control. The cost to the clean coal producer for air and water pollution control depends on many site-specific factors. The installation and operating costs of air pollution control equipment can be estimated from the hypothetical cases listed in Table 22. Water treatment equipment often is installed for increased coal yield, reduction of product coal moisture content, and clarification of water for recirculation. Therefore, the purpose of water treatment equipment determines whether it should be considered a pollution control cost.

Chemical Coal Cleaning

There are currently 29 chemical cleaning processes under active development and many more under conceptual development.⁽⁵⁻¹⁴⁾ Of these 29, only 11 have any economic information published or available. These 11 are described below.

Meyers/TRW Process

The Meyers/TRW process is the most highly developed chemical cleaning process. It has been studied by Dow Chemical, Bechtel, and Dynatech.⁽⁵⁻¹²⁾ The process leaches -149 μm (-100 M) coal containing iron pyrite (FeS_2) with ferric sulfate ($\text{Fe}_2(\text{SO}_4)_3$), converting the pyrite to sulfuric acid, ferrous sulfate, and elemental sulfur, at moderate temperatures and pressures, 50 C to 130 C (120 F to 270 F), and 100 kN/m^2 to 1000 kN/m^2 , (15 to 150 psi), with long leaching times (1 to 16 hours). The process removes 80 to 99 percent of the pyritic sulfur from -14 M coal. Elemental sulfur is produced as a by-product. Figure 19 indicates the layout unit processes involved in the Meyers/TRW process.

TABLE 22. ESTIMATED COSTS OF AIR POLLUTION CONTROL EQUIPMENT FOR TWO TYPES OF 1000 TPH COAL CLEANING PLANTS (5-7, 5-8, 5-9)
(1977 Dollars)

Plant Type(a)	Emission	Control Equipment	Installed Cost of Control Equipment, \$/TPH	Annual Operating Cost of Control Equipment(b), cents/ton
X, Y	Dust from crushing and sizing operation	Dust enclosures with dry bag collectors	36	0.1
		Dust enclosures with high-efficiency wet scrubbers	20	0.2
X	Dust from air tables operating on medium-size coal	Primary cyclones followed by dry bag collectors	360	2.8
		Primary cyclones followed by high-efficiency wet scrubbers	200	9.7
Y	Thermal dryer off-gas	Primary cyclones with high-efficiency wet scrubbers	250	12.2
		Primary cyclones with high-efficiency wet scrubbers followed by limestone scrubbing	9,250	93.8

(a) Both plant types X and Y include crushing and sizing operations and coarse (3 x 3/8 inch) coal beneficiation by jigs or dense medium vessels. Plant type X includes pneumatic tables for medium (3/8 inch x 28 M) and fine (28 M x 0) coal beneficiation. Plant type Y includes wet concentrating tables or dense medium cyclones for medium size coal beneficiation and hydrocyclones or froth flotation for fine coal beneficiation.

(b) Excludes capitalization, depreciation, and interest. Based on 180 (2-shift) days.

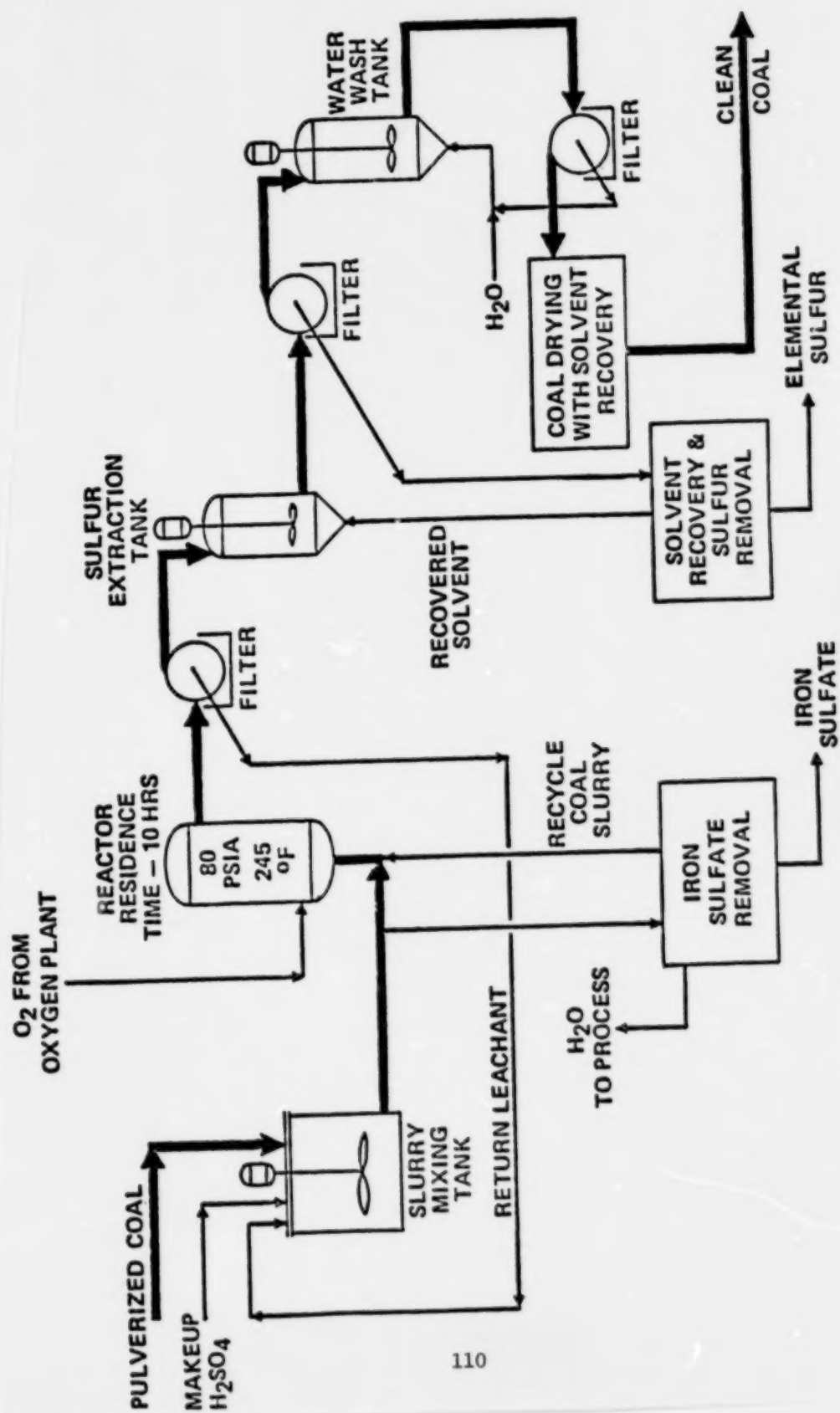


FIGURE 19. MEYERS/TRW PROCESS FLOW DIAGRAM

Dow Chemical⁽⁵⁻¹⁰⁾ has done an extensive design and economics study of this process for a 420 kkg (380 short tons) per hour plant. Their total capital cost for this design was \$145 million (mid-1975 dollars) plus or minus about 20 percent. This includes limited physical cleaning facilities for removal of rock aggregate and shales. Dow⁽⁵⁻¹³⁾, feels that based on this design and 94 percent removal of pyritic sulfur, a cleaning cost of \$11 to \$15.50 per kkg (\$10 to \$14 per ton) of cleaned coal would be appropriate currently. TRW⁽⁵⁻¹⁴⁾ has studied the economics of a 300 kkg (330 short ton) per hour plant suggesting a total capital cost of \$109 million and a cleaning cost of \$0.58 per GJ (\$0.61 per million Btu's), or \$17.28 per cleaned kkg (\$15.67 per cleaned short ton). Both companies' costs contain no profit margins, and Dow's cost is based on cleaning a Pennsylvania Lower Kittanning coal. Dow indicates that, based on their design, the process can achieve a 90 percent Btu recovery, while TRW indicates 94 percent Btu recovery.

The Meyers/TRW process may be one of the more troublesome chemical cleaning processes from an environmental standpoint. It uses organic solvents in contact with process wastes to extract the elemental sulfur. A portion of the solvent is left in the cleaned coal. The waste products of the process, ferrous sulfate, sulfuric acid, and physical cleaning refuse, all of which contain higher concentrations of trace elements than the raw coal, have to be disposed of properly with pH adjustment. This refuse is obviously much more acidic than just physical cleaning refuse alone. Internally, the process must use a closed water circuit with solvent recovery to avoid further effluent problems.

The Meyers/TRW process probably could be commercial in 5 to 6 years. A 9 metric ton per day pilot plant has been constructed. Information from this should help provide scale-up information.

Battelle Hydrothermal

The Battelle process⁽⁵⁻¹⁵⁾ leaches $-149 \mu\text{m} + 4 \mu\text{m}$ ($-100 + 200 \text{ M}$) coal with sodium and calcium hydroxide solutions at elevated temperatures and pressures 98 C to 170 C (200 F to 340 F) and 1.55 MN/m^2 to 17.25 MN/m^2 (225 psia to 2500 psia). The process removes up to 99 percent of the mineral sulfur and has demonstrated 24 percent to 72 percent organic sulfur removal, depending

on the specific coal processed. Btu recovery ranges from 75 to 90 percent, depending on process operation. Figure 20 indicates the process layout and unit operations. The capital cost of the process suffers due to the elevated temperatures and pressures used in the system, and the need for leachant regeneration equipment to close the process water loop, preventing the loss of leachant.

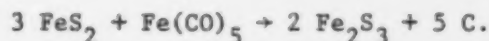
Battelle currently reports that an operating cost of \$19.85 to \$33.08 per kkg (\$18 to \$30 per short ton) of cleaned coal or about \$0.95 per GJ (\$1.00 per million Btu) is a good estimate⁽⁵⁻¹⁶⁾ based on the regeneration of leachant, 0.25 hour leaching time, and processing a Lower Kittanning coal from 2.4 to 0.9 percent sulfur. Under these conditions a capital cost of \$134 million to \$145 million* has been estimated for a 360 kkg (400 short tons) per hour plant, the cost depending on the coal to leachant ratio (2 to 1, or 3 to 1). No profit margin is included in these figures.

With leachant regeneration, internal process water loops are closed, so that the only water effluent is in the wet coal. Hydrogen sulfide (H_2S) is produced in the process, and protection against H_2S leakage would be necessary both from a processing and safety point of view. The process is known to leach out many heavy metals in coal. Any effluents containing high concentrations of these metals may require specific disposal.

The Battelle hydrothermal process could be commercialized in 4 to 6 years.

Hazen Magnex Process

The Hazen Process⁽⁵⁻¹¹⁾, or Magnex Process, shown in Figure 21 is a totally dry process. The process reacts iron pyrite with gaseous iron pentacarbonyl:



The Fe_2S_3 is much more magnetically susceptible, enabling it to be magnetically separated from the coal. Thus, this process can remove only mineral sulfur, and requires very fine grinding of the coal in order to liberate the pyrite particles. This may restrict application of the Hazen process. The process

* Versar⁽¹⁴⁾ reports a capital cost of $\$169 \times 10^6$.

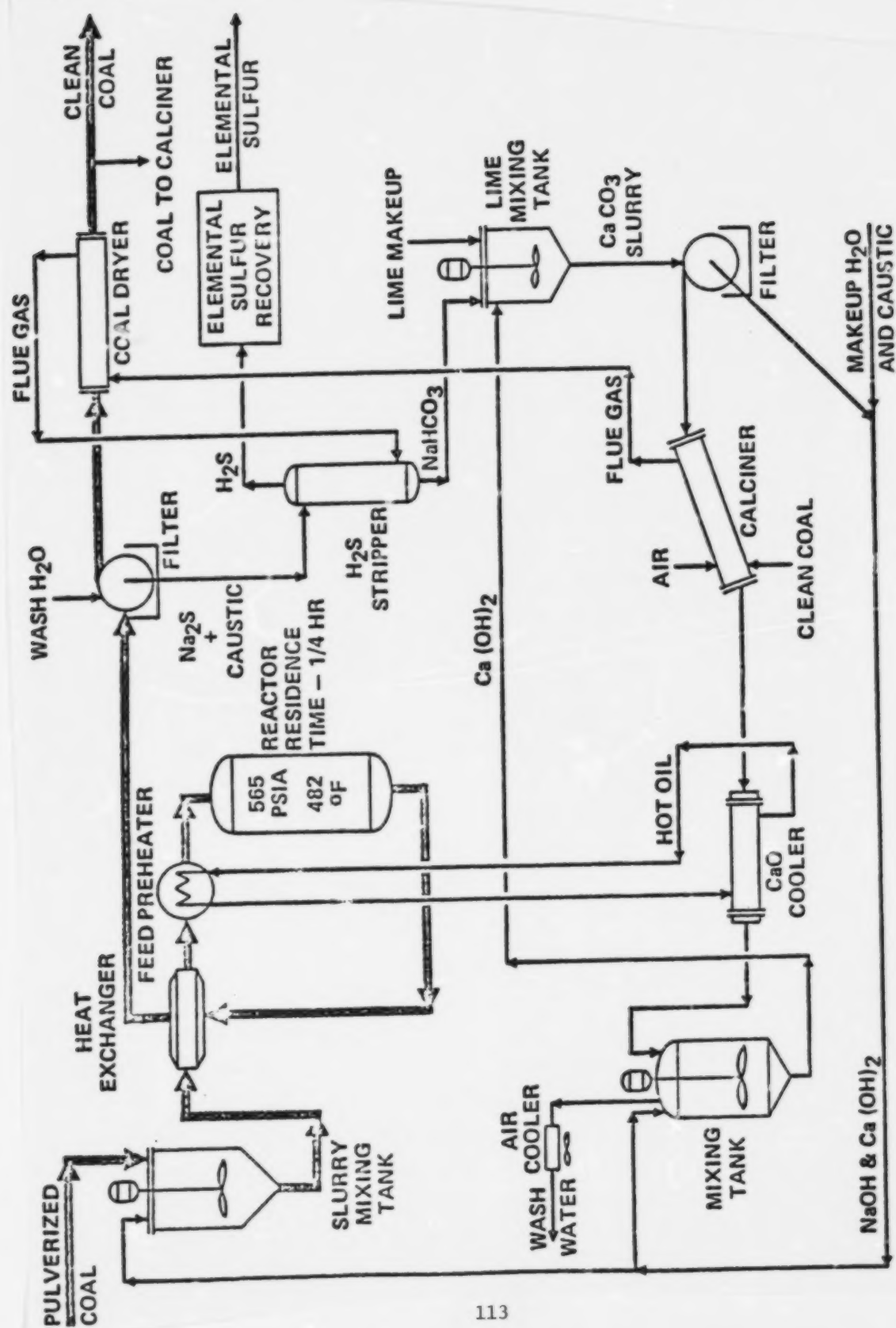


FIGURE 20. BATTELLE HYDROTHERMAL PROCESS FLOW DIAGRAM

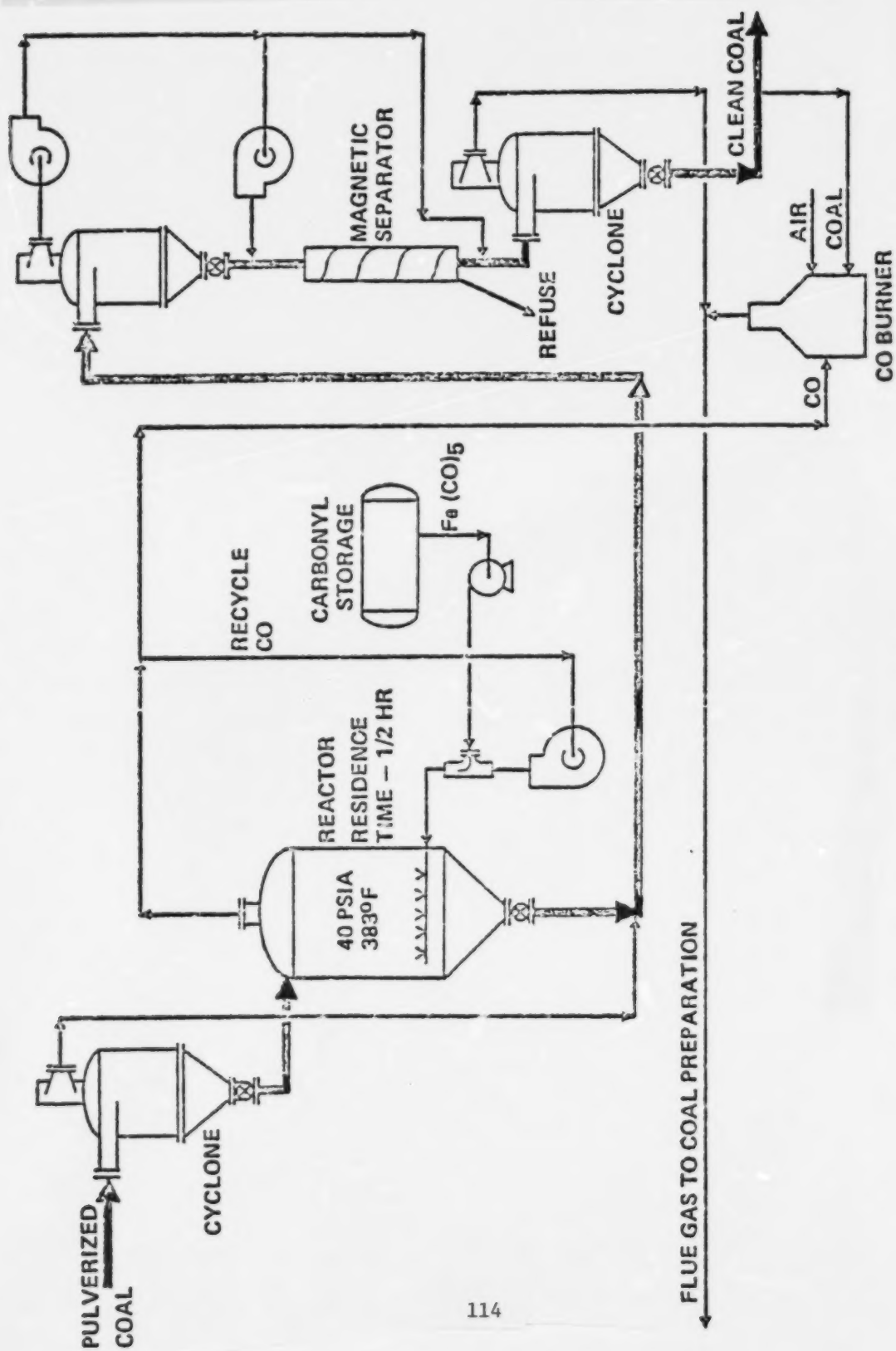


FIGURE 21. HAZEN PROCESS FLOW DIAGRAM

is simpler than others, using fewer unit operations and process steps, at mild temperatures and pressures. The process does have severe process monitoring requirements due to the use of highly toxic iron pentacarbonyl.

Results reported to date have been limited to coal ground to 1.19 mm (14 M) because there are no magnetic separators available to handle dry, fine-pulverized materials. This will hinder development of the process.

Bechtel⁽⁸⁾ has estimated costs for a 300 kkg (330 short tons) per hour plant for a Pittsburgh bituminous coal as a capital cost of \$38 million, and operating and maintenance costs of about \$10.12 per kkg (\$9.18 per short ton) cleaned. They indicate a cleaning cost of \$.35 per GJ (\$.37 per million Btu), with a Btu recovery of 80 percent. There are few aspects of Bechtel's design that are specified. One specified is the $\text{Fe}(\text{CO})_5$ cost. Hazen estimates its cost at \$.10 per pound with a consumption of 32 pounds per ton of coal (whether ROM or cleaned is not specified). Private vendor prices for $\text{Fe}(\text{CO})_5$ go as high as \$3.30 per kkg (\$1.50 per pound). This higher price would change the cleaning costs dramatically.

Along with monitoring $\text{Fe}(\text{CO})_5$ levels in the plant area, the disposal of the refuse will be of environmental concern. Problems involved will be very much the same as those for refuse from physical cleaning, except that Hazen refuse, because of its small particle size, will create severe dusting problems.

Hazen is considering a 0.9 kkg (1 ton) per day plant, so commercialization might be in 6 to 8 years.

KVB

The KVB process^(5-11,5-12), shown in Figure 22, oxidizes sulfur components of dry pulverized -1.19 mm + 0.595 mm (-14 + 28 M) coal with NO_2 followed by caustic leaching to solubilize and remove the sulfur compounds formed in the oxidation step. The soluble sulfur compounds are mixed with lime to regenerate caustic and precipitate gypsum (CaSO_4), and iron oxides, which would be land-filled. The advantages of the KVB process are its claim to removal of both mineral and organic sulfur (up to 63 percent sulfur removal with oxidation, 89 percent with additional caustic leaching), the simplicity and low costs of dry oxidation, and the moderate temperatures, pressures, and vessel residence times. Potential problem areas in the system are nitrogen uptake

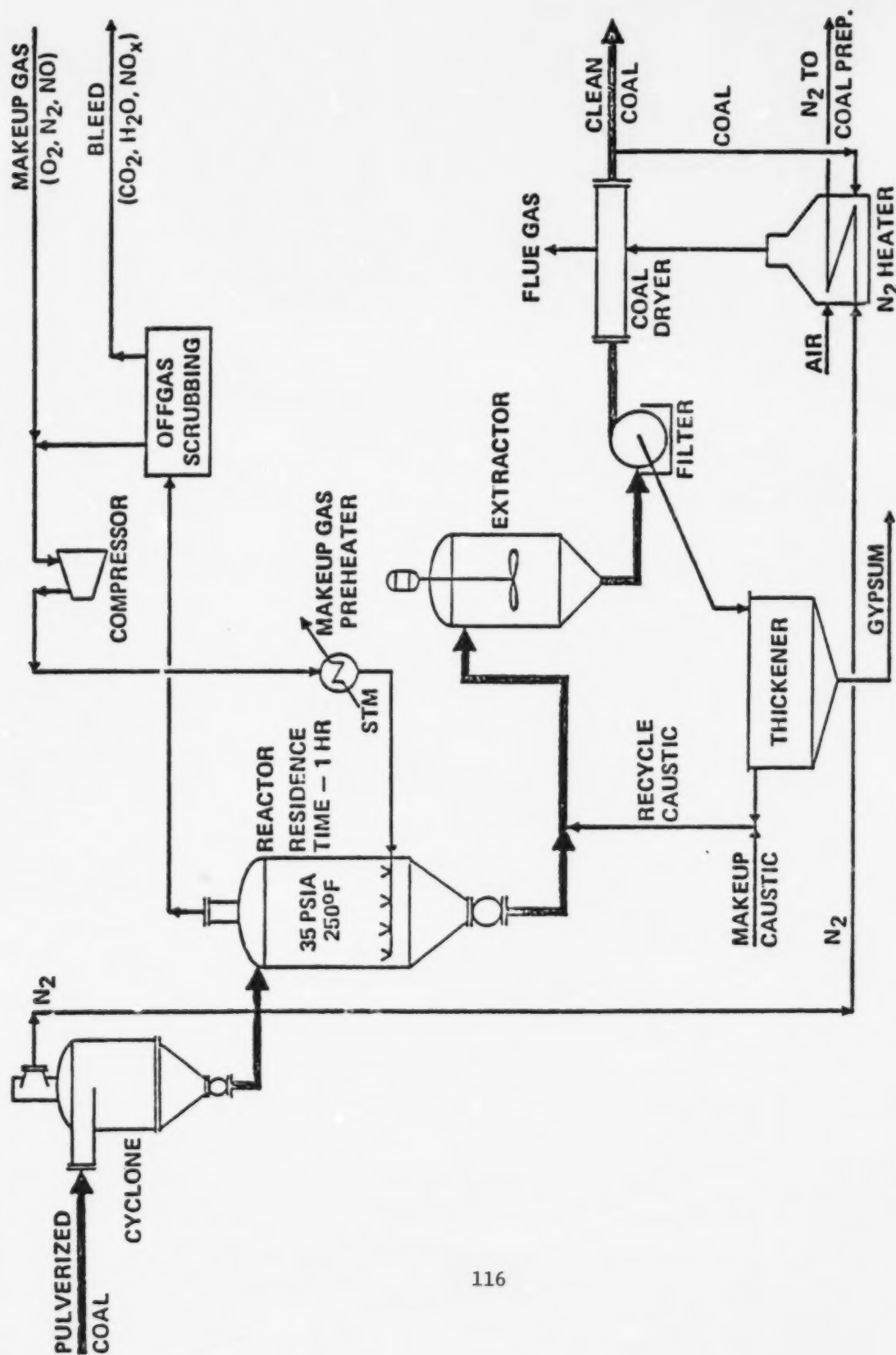


FIGURE 22. KVB PROCESS FLOW DIAGRAM

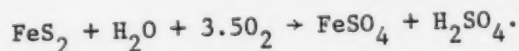
by the coal and oxygen concentration requirements in the treat gas which exceed the explosion limits for coal.

Bechtel has developed cost information on the KVB process, based on the KVB patent and limited nonproprietary information (no literature is available and little bench scale work has been done). Bechtel indicates a capital cost of \$66 million for a 300 kkg (330 short tons) per hour plant with an operating and maintenance cost of \$20.10 per kkg of cleaned coal (\$18.23 per cleaned short ton). They indicate a cost of \$0.65 per GJ (\$0.69 per million Btu), for a Pittsburgh bituminous coal, with 91 percent Btu recovery.

Environmentally, the KVB process has one major problem; it is a NO_x producer. No information is available on expected effluent levels of NO_x . The other waste product is gypsum, for which established disposal technologies are available.

Ledgemont Oxygen Leaching

The Ledgemont process^(5-11,5-12), (LOL) (see Figure 23) is based on the following reaction:



High temperatures and pressures must be used to speed the reaction rate for a commercially viable process. Strong oxidizing conditions in the reactor cause some coal loss and volatilization in the reactor. This results in loss of heating value. The process has no significant organic sulfur removal capability. Sulfur is removed from the system by mixing the reaction products with lime, producing gypsum and iron oxides which would be land-filled. Kennecott Copper Company claims 95 percent pyritic sulfur removal in the LOL process, with 93 percent Btu recovery. There has been no R&D effort on the process since 1975.

Dynatech and Bechtel^(5-11,5-12) have studied the economics of the LOL process. Dynatech's study gives an operating cost of \$7.60 per kkg (\$6.90 per short ton) cleaned, but no capital costs. Bechtel's study gives a capital cost of \$114 million for a 300 kkg (330 short tons) per hour plant with an operating cost of \$21.03 per kkg (\$19.07 per cleaned short ton) or \$0.70 per GJ

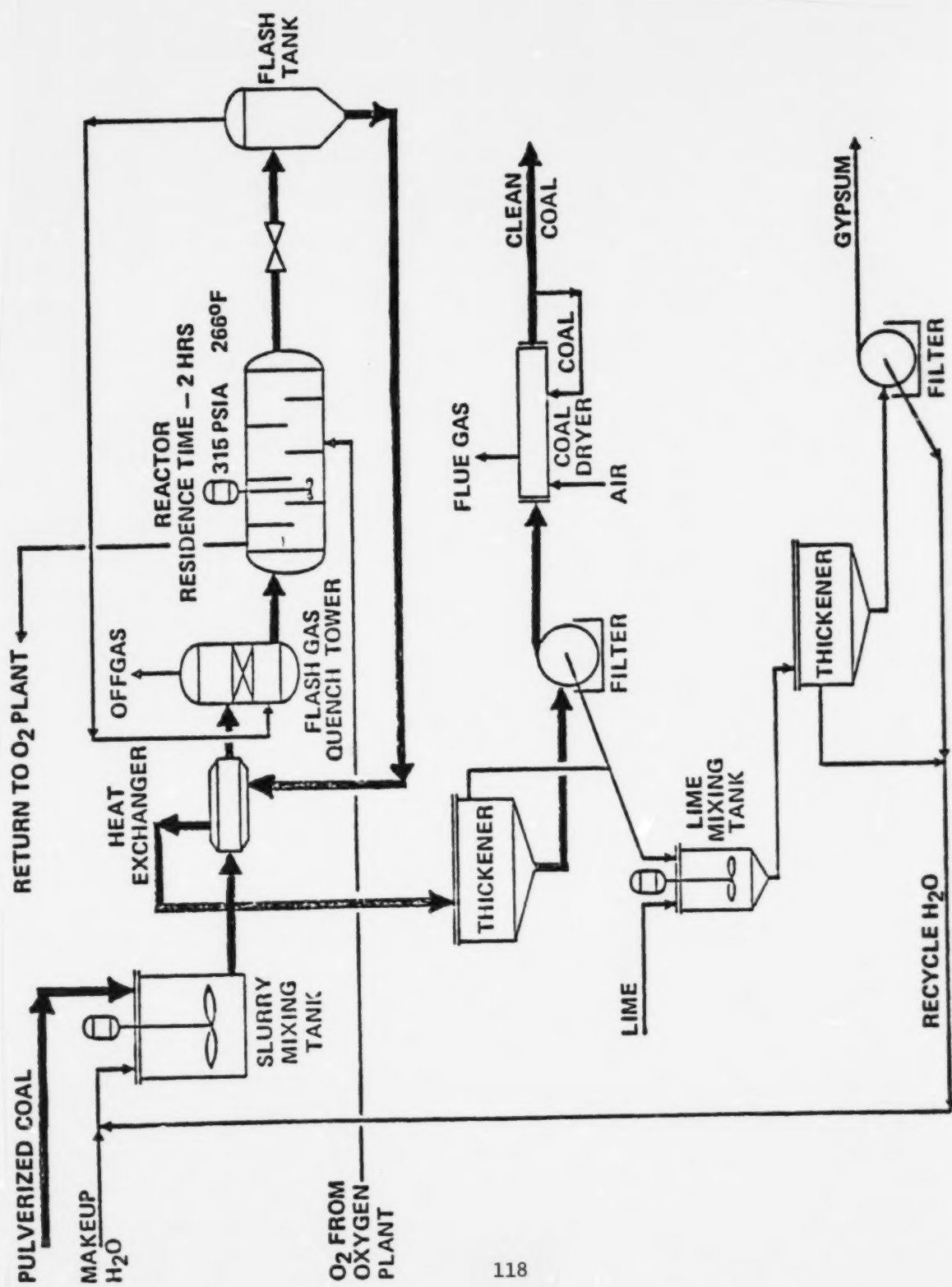


FIGURE 23. LOL PROCESS FLOW DIAGRAM

(\$0.74 per million Btu). Dynatech does not indicate what coals were used as a design base, or what type of preparation facilities were included in the cost case. Bechtel indicates a Pittsburgh A bituminous coal pulverized to 80 percent -74 μm (100 M).

ERDA

The ERDA process⁽⁵⁻¹¹⁾ (see Figure 24) uses wet oxidation, employing air instead of oxygen as used by LOL. The ERDA process operates at higher temperatures (150 to 200 C) and pressures (34 to 102 atm) than LOL, generating iron sulfates and sulfuric acid. Because of the extreme operating conditions, both pyritic and organic sulfur removal are claimed, and the process can be expected to show coal loss similar to the LOL process. Lime is used to convert from sulfates to iron oxides and gypsum.

Versar⁽⁵⁻¹⁴⁾ has studied the economics of this process using a Pittsburgh bituminous coal. With pulverization facilities, grinding to 80 percent -74 μm (200 M), Versar estimates a capital cost of \$167 million and an operating and maintenance cost of \$26.26 kkg of cleaned coal (\$23.82 per cleaned short ton), or \$0.92 per GJ (\$0.97 per million Btu) with a Btu recovery of 94 percent. These costs are for a 300 kkg (330 short tons) per hour plant.

Environmentally, the ERDA process will be very similar to the LOL process. The process is under bench scale development, so commercialization would be about 6 to 9 years off.

General Electric (GE)

GE is developing a process⁽⁵⁻¹⁴⁾ that radiates coal with microwaves as a means of removing the sulfur values. Crushed and ground coal, 420 to 149 μm (40 to 100 M), is contacted with a sodium hydroxide solution, then exposed to microwave radiation for less than 30 seconds. Pyritic and organic sulfur forms are reacted to form soluble sodium sulfide (Na_2S) and polysulfides (Na_2S_x). Physical coal washing is used to remove the soluble sulfides. This procedure is repeated, removing additional sulfur. Single treatments yield 30 to 70 percent sulfur removal, while two microwave treatments yield 70 to 99 percent sulfur removal. GE has not published a process flowsheet; however, Versar⁽⁵⁻¹⁴⁾ has presented the flowsheet in Figure 25.

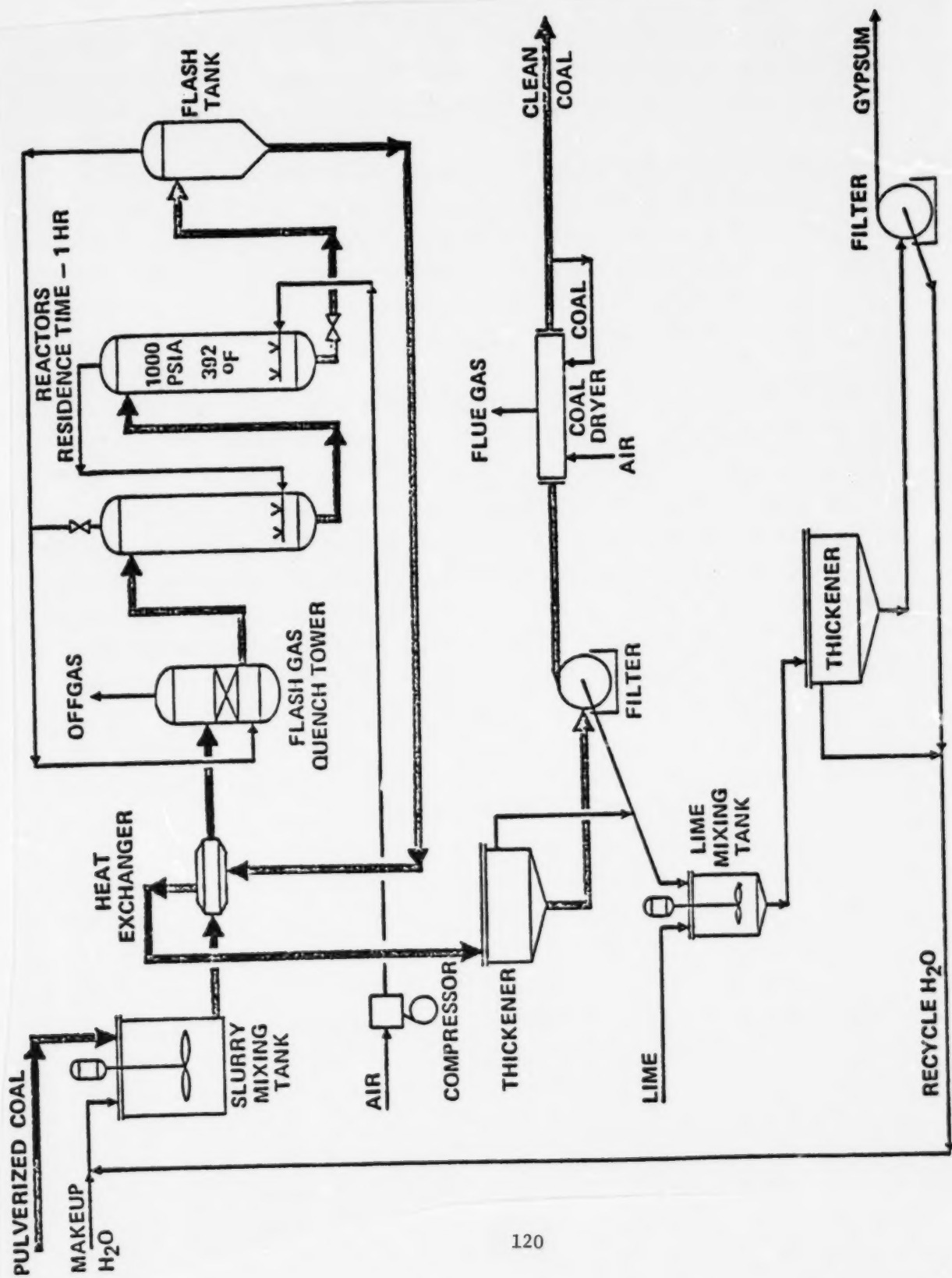


FIGURE 24. ERDA PROCESS FLOW DIAGRAM



GE's preliminary cost data⁽⁵⁻¹⁴⁾ for a 300 kkg (330 ton) per hour plant are as follows. Installed capital costs for the plant are \$102 million with an operating and maintenance cost of \$17.33 per kkg of cleaned coal (\$15.72 per cleaned short ton), or \$0.61 per GJ (\$0.64 per million Btu) with a 96 percent heating value recovery.

The GE process is currently being developed for 1 kg quantities. Process commercialization will not occur in the near future.

Syracuse Process

The Syracuse process⁽⁵⁻¹⁴⁾ chemically comminutes 3.8 cm (1-1/2 in.) top size coal by exposure to moist ammonia vapor at intermediate pressure. After the ammonia has been removed, conventional coal cleaning can remove 50 to 70 percent of the pyritic sulfur. The ammonia disrupts the natural bonding forces across the internal boundaries of the coal structure. As a result, the apparent bond breakage exposes the ash and pyrite for physical separation. There is no significant dissolution of coal and there is no apparent reaction with the ammonia. A process flow sheet is presented in Figure 26.

Versar, using Catalytic, Inc. cost data has reported⁽⁵⁻¹⁴⁾ the process economics for a 300 kkg (330 short ton) per hour plant with coarse coal cleaning included. Installed capital costs for this plant are \$49 million with maintenance and operating costs of \$6.36 per kkg cleaned coal (\$5.77 per short ton cleaned coal), or \$0.19 per GJ (\$0.20 per million Btu). The operating costs are based on a 95 percent recovery of the coal heating value.

Research on this process began in 1971. Currently, tests have been run on batches as large as 23 kg (50 lb) of coal.

JPL (Jet Propulsion Laboratory) Process

The JPL process converts pyritic and organic sulfurs in coal to sulfuric acid by using chlorine gas as an oxidizing agent in solution with tri-chloroethane. Coal is ground to 149 to 74 μ m (100 to 200 M) and suspended to 1,1,1-trichloroethane at 74 C (165 F). Chlorine gas is sparged into the suspension at atmospheric pressure for 1 to 4 hours. The coal is distilled for recovery of excess chlorine and hydrochloric acid, which is then converted to chlorine. The process is illustrated in Figure 27.

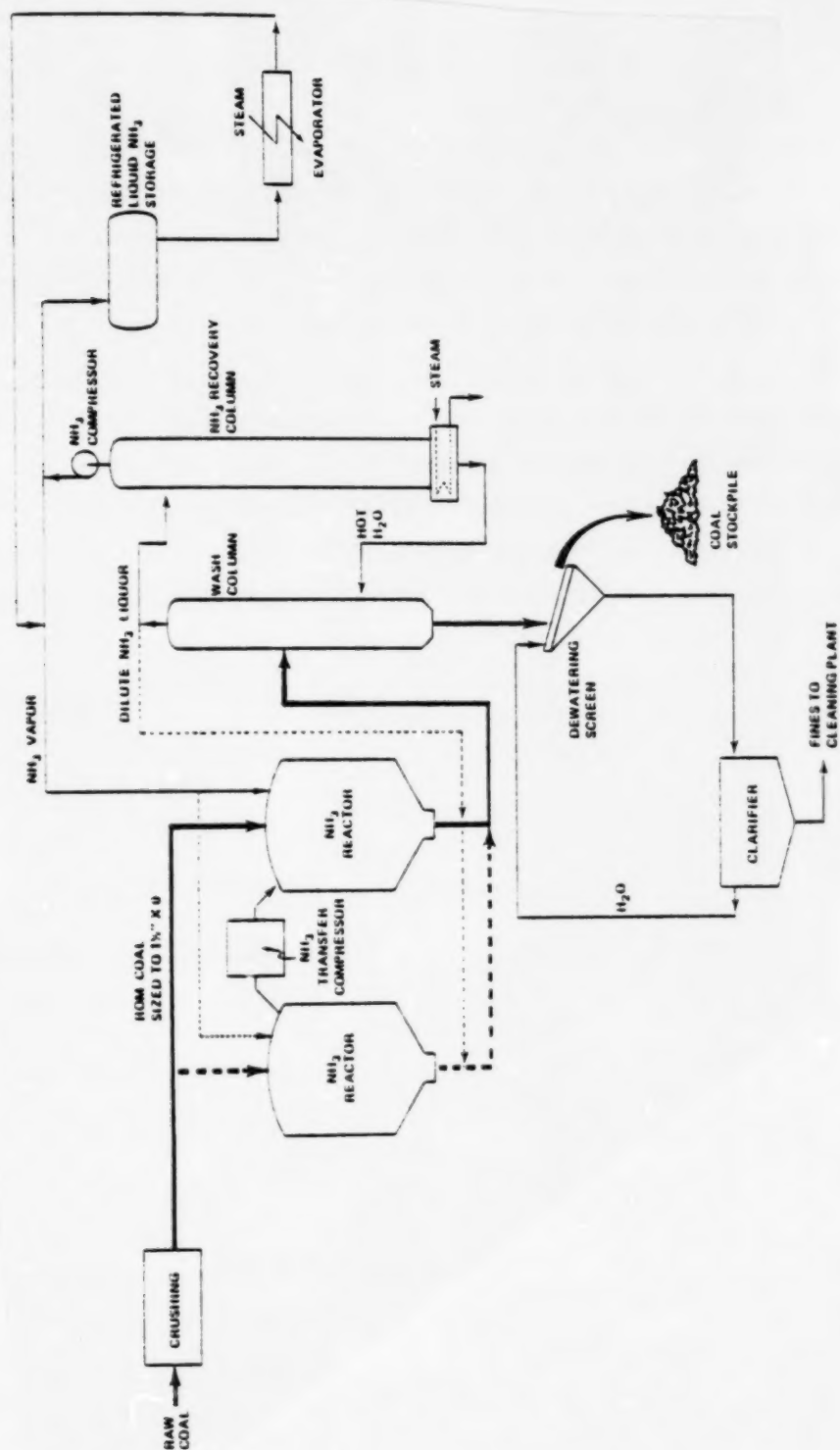


FIGURE 26. SYRACUSE COAL COMMUNITION PROCESS FLOW SHEET (5-14)

Problem areas which can adversely effect the technical and economic feasibility of this process include the corrosive nature of chlorine, hydrogen chloride, hydrochloric acid, and sulfuric acid, which are all present in the process; and the contamination of the by-product sulfuric acid with trace metals from the coal which will make the acid difficult to sell.

Versar⁽⁵⁻¹⁴⁾ presents an economic evaluation of a 300 kg (330 short tons) per hour plant based on cost data supplied by JPL. The installed capital cost is \$103 million with an operating and maintenance cost of \$20.39 per kkg of cleaned coal (\$18.99 per short ton of cleaned coal) or \$0.71 per GJ (\$0.75 per million Btu). The operating costs are based on a 91 percent heating value recovery.

Currently, development plans indicate that 1 kg batch tests will be initiated. At a later date, a 1 kg/hr mini-pilot plant will be constructed.

IGT Process

The IGT process employs atmospheric pressures and high temperatures (815 C or 1500 F) to hydrodesulfurize coal. Due to the high temperatures, a large amount of coal is lost due to oxidation, volatilization, and gasification. The treated product is a char with about 80 to 90 percent of the total sulfur removed. Experimental results indicate a 57 percent heat recovery for this process with utilization of the gases produced. Figure 28 illustrates the process flow diagram for the IGT process.

Heat and material balance information has not been determined for the IGT process. Versar⁽⁵⁻¹⁴⁾ estimated the IGT process economics based on the similar unit operations used by the Lurgi gasification process. Based on a 300 kkg (330 short tons) per hour plant, the installed capital costs are \$135 million with operating and maintenance costs of \$26.64 per kkg of clean coal (\$24.16 per ton of clean coal). This corresponds to \$0.93 per GJ (\$1.03 per million Btu). The estimate is based on a 57 percent heating value recovery.

This process is currently being studied at the bench scale level.

ARCO Process

Atlantic Richfield (ARCO) has been developing this coal cleaning process on their own. Only recently has the Electric Power Research Institute (EPRI)

TABLE 23. MAJOR CHEMICAL COAL CLEANING PROCESS COSTS AND OPERATING DATA (a) (5-10--5-16)

Process	Plant Size Basis, short tons/hr	Costs			Sulfur Removal		Weight Yield, %
		Capital, \$ x 10 ⁶	Processing (b) \$/ton	\$/10 ⁶ Btu	Pyritic, %	Organic, %	
TRW/Meyers	330	109	15.67(43.45)	0.61(1.69)	95	--	94
Battelle Hydrothermal	400	169	29.58(55.90)	1.30(2.45)	99	24-72	88
Hazen (Magnex)	330	38	9.18(40.67)	0.37(1.64)	80	--	80
KVB	330	66	18.23(47.54)	0.69(1.81)	95	up to 85	91
Ledgemont	330	114	19.07(46.85)	0.74(1.82)	50-70	--	94
ERDA	330	167	23.82(51.60)	0.92(2.00)	99	up to 40	94
GE	330	102	15.72(41.77)	0.64(1.69)	[70-99 total S]		96
Syracuse	330	49	5.77(37.02)	0.20(1.27)	50-70	--	95
JPL	330	103	18.49(45.97)	0.75(1.86)	90	up to 70	91
IGT	330	135	24.16(65.83)	1.03(2.81)	95	up to 85	57
Arco	--	--	17 to 31	--	95	--	--

(a) See text for basis for costs and other data.

(b) Includes capital charge plus operating and maintenance costs, based on clean coal. Numbers in parentheses include raw coal cost at \$25/short ton; others exclude coal cost.

helped finance this study. As a result, little information is available. The process, using a reaction promoter, will remove both pyritic and organic sulfur. Sulfur reduction is up to 98 percent for pyritic sulfur and 20 percent for organic sulfur. In addition, a 78 percent reduction of ash is reported. Processing costs are reported to be in the range of \$17 to \$31 per ton of clean coal.

Currently, this process is being developed using batch bench scale experiments.

Summary of Coal Cleaning Costs

A summary of the costs of various coal cleaning processes is given in Table 23, together with the ranges of sulfur removal and Btu recovery claimed for each process.

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SECTION 6

RELATIVE ECONOMICS OF SULFUR EMISSION CONTROL TECHNIQUES

Introduction

Emphasis in programs directed at the control of sulfur oxide emissions from fossil-fuel-fired combustors has focused on both precombustion and postcombustion control methods. Currently, the methods being explored for the control of SO_2 emissions from coal-fired units fall into five categories: (1) the use of naturally occurring low-sulfur coal; (2) physical coal cleaning (PCC) to reduce the sulfur and ash content of the coal; (3) chemical coal cleaning to remove sulfur from coal; (4) conversion of coal to another form of fuel (relatively sulfur-free) through gasification or liquefaction; and (5) flue gas desulfurization (FGD). Of these five methods, the use of naturally occurring low-sulfur coal, FGD, PCC, and the combined use of PCC and FGD are the only ones currently technologically feasible.

Although these latter methods may be feasible, the ultimate attractiveness of each in meeting the SO_2 emissions standards with a particular coal depends on the cost of the method to the user. Unfortunately, the cost to the user cannot always be determined in an unambiguous manner. Not only do the perceived costs depend on the specific use situation, but sometimes on the individual doing the computation, on the rigidity of an accounting system, or on rigidity imposed by government regulation. In another sense, government regulation imposes sulfur emissions control in the first place and has, in the past, sometimes forced the use of costly control methods because of the bias or inflexibility inherent in some regulatory legislative forms.

Even though the ultimate objective of any presentation or discussion, such as this one, of relative costs of competing control methods is to achieve clarity and unambiguity, this is probably never possible because the relative costs are case-dependent and, in any generalized analysis, the assumed conditions may never be satisfactorily stated. But, the desire of

the authors exists to enhance understanding of methods and procedures and to provide clear, honest, complete, and representative examples of costs for these competitive control methods, and to use these costs for comparing the ultimate utility and economic viability of each method.

The specific objective of this analysis is to compare the costs of the current technologically feasible SO₂ emission control methods previously mentioned: naturally occurring low-sulfur coal, FGD, PCC, and the combined use of FGD and PCC. The procedure utilized in the analysis is (1) to compare and analyze the results of previous comparative studies; (2) to utilize these results and comparisons to develop further more accurate, reliable estimates of direct costs and benefits; and then (3) to go the final step of evaluating the influence of the performance of complete energy conversion systems on the cost and attractiveness of the competing control methods.

Components of Costs and Benefits

Naturally Occurring Low-Sulfur Coal

The cost of naturally occurring low-sulfur coal is made up, primarily, of the FOB mine price plus the transportation cost. Inasmuch as a lot of current interest exists in the use of low-sulfur western coal, the ratios of transportation costs to FOB mine prices is considerably different than traditionally observed in the use of eastern coals. Transportation costs of western coals to eastern markets may approach or even exceed the FOB mine price.

In the use of western coals, the lower Btu values and different coal properties may lead to inferior performance in boilers designed for eastern coals. Thus, a penalty in addition to high fuel cost may need to be levied against the western coals.

Flue Gas Desulfurization

Flue gas desulfurization systems comprise a relatively sophisticated process for removing sulfur dioxide from combustion gases. As such, they have a high initial cost, require diligent and competent maintenance to keep them running, and have a continuing waste disposal problem. These factors, plus raw materials, represent the costs to be assessed against the FGD system.

In the past, because of less-than-adequate maintenance, poor attention to design details, and improper use of materials, many FGD systems have not had sufficient availability. This low availability has penalized utilities with high fixed charges and replacement power costs. However, as FGD systems are improved, the availability should also improve, particularly if proper maintenance procedures are adopted and diligently followed. This will lead, hopefully, to more reasonable costs and system availabilities.

Physical Coal Cleaning

The cost associated with producing physically cleaned coal at the mine site is derived from the following factors: (1) the amortized capital cost of the cleaning plant; (2) operating and maintenance costs of the cleaning plant; (3) loss of heating value in the rejected material during the cleaning operation; and (4) cost of the raw coal, disposal of wastes, and control of other effluents. The benefits directly attributed to burning clean coal are as follows: (1) transportation costs are reduced because less coal is shipped due to the increased heating value; (2) ash disposal costs for the utility are reduced; (3) coal pulverizing costs are reduced; (4) benefits paid to the mine operations Pension and Benefit Trust Fund are reduced because fewer tons of coal are shipped from the mine to equal the same heating value; and (5) power plant maintenance costs are reduced by using coal with lower ash and sulfur content. Other indirect benefits to the power plant associated with burning clean coal result from increased plant efficiencies, longer plant life, and increased boiler availability.

Combined FGD and PCC

In the event of a combined emission control system of physical coal cleaning and flue gas desulfurization, it becomes necessary to determine the effects of physically cleaned coal on the FGD system. The benefits to the FGD system result from a reduced quantity of flue gas to be treated and consequently units of smaller size and capacity. Therefore, costs for energy, labor, chemicals, maintenance, supplies, overhead, working capital, sludge disposal, and land requirements for both the scrubber system and sludge disposal systems are all reduced.

In order to determine the net cost of coal cleaning, it is necessary to incorporate in any evaluation all of the costs and benefits of using clean coal. However, many of the indirect costs and benefits to the utility and FGD system from using clean coal are very difficult to quantify.

Direct Costs and Benefits of the Several Control Methods

Review of the Hoffman-Muntner Study

A study by Hoffman-Muntner Corporation⁽⁶⁻¹⁾ compares the costs of a combined SO₂ control system of FGD and physical coal cleaning to FGD alone. Many of the benefits of coal cleaning are accounted for in this study but some are not. Table 24 illustrates the cost of SO₂ control technology for 12 different cases of both new and existing boilers with capacities of 500 MWe. The costs are reported as a range of values due to the variability in the price of coal. In all but one case, the cost of the combined use of physical cleaning and FGD is less than the cost of FGD alone.

For existing power plants, the actual costs of FGD systems are higher than for new plants due to the higher capital costs of retrofitting and shorter economic lives of the systems. Therefore, in existing boilers the use of physical coal cleaning followed by flue gas desulfurization of a portion of the flue gas can be especially attractive.

TABLE 24. HOFFMAN-MUNTNER ESTIMATES OF COST OF MEETING SO₂ EMISSIONS STANDARDS WITH SO₂ CONTROL TECHNOLOGY⁽⁶⁻¹⁾ (1977 dollars)^(a)

Power Plant Location	Raw Coal Location	Case Description				Cost of SO ₂ Control Technology, \$/10 ⁶ Btu	
		Type of Plant	Emission Standard, lb SO ₂ /10 ⁶ Btu	% Sulfur in Raw Coal	% Ash in Raw Coal	FGD Alone (Includes Coal Cost)	PCC/FGD (Includes Coal Cost)
Tennessee	Indiana	New	1.2	1.9	10.5	0.67-0.83	0.63-0.81
		Existing	1.2	1.9	10.5	0.80-0.96	0.77-0.89
New York	Pennsylvania	New	1.2	2.4	11.4	1.18-1.33	1.06-1.23
		Existing	1.4	2.4	11.4	1.11-1.26	1.02-1.20
Michigan	Ohio	New	1.2	2.3	10.4	0.71-0.86	0.62-0.79
		Existing	1.6	2.3	10.4	0.80-0.95	0.61-0.79
Massachusetts	Pennsylvania	New	0.28	0.85	9.3	0.79-1.10	0.74-1.07
		Existing	0.28	0.85	9.3	0.91-1.22	0.79-1.12
Michigan	West Virginia	New	1.6	2.24	18.5	0.83-1.00	0.72-0.92
		Existing	1.6	2.24	18.5	0.95-1.12	0.77-0.96
Massachusetts	Pennsylvania	New	0.55	2.53	13.0	0.76-0.92	0.64-0.82
		Existing	0.55	2.53	13.0	0.91-1.07	0.71-0.90
Michigan	Ohio	New	1.6	2.82	9.8	0.68-0.83	0.65-0.83
		Existing	1.6	2.82	9.8	0.81-0.96	0.76-0.93
Tennessee	Indiana	New	1.2	1.54	12.0	0.66-0.83	0.61-0.80
		Existing	1.2	1.54	12.0	0.78-0.95	0.66-0.85
New Jersey	Maryland	New	0.3	2.37	13.8	Will not meet stds.	
		Existing	1% SO ₂ by wt.	2.37	13.8	1.04-1.19	0.95-1.12
Wisconsin	Illinois	New	1.2	1.12	14.8	1.66-0.83	0.61-0.81
		Existing	1.2	1.12	14.8	0.74-0.91	0.66-0.86
New Hampshire	Pennsylvania	New	1.5	3.45	11.4	1.01-1.16	0.93-1.10
		Existing	1.5	3.45	11.4	1.12-1.27	0.96-1.13
		New	1.2	3.45	11.4	1.11-1.26	1.09-1.27
Maryland	West Virginia	New	1% SO ₂ by wt.	3.8	11.0	0.91-1.06	0.84-1.02
		Existing	1% SO ₂ by wt.	3.8	11.0	1.07-1.22	0.96-1.13

(a) All of the cost comparisons in this discussion of relative economics of sulfur emission control techniques are based on the following parameters:

Power plant capacity: 500 MWe
 Amortization period: 10 years
 Interest (discount) rate: 9 percent
 Utilization factor for coal cleaning plant: 30 percent
 Availability of FGD system: 100 percent.

The cost for combined SO₂ removal with physical coal cleaning (PCC) and FGD compares favorably with the cost of western low-sulfur coal. The average term FOB mine price for coal from five western regions is reported in a recent issue of Coal Week⁽⁶⁻²⁾ to be \$0.80/10⁶ Btu. The transportation charge from Wyoming and Montana to Chicago by unit train is approximately \$12.95/ton. For a heating value of 10,550 Btu/lb (the average heating value of the five western regions considered), the transportation charge is \$0.61/10⁶ Btu. Therefore, the total cost of low-sulfur western coal is \$1.41/10⁶ Btu, which is 18 to 130 percent higher than combined PCC-FGD SO₂ control and 6 to 114 percent higher than FGD alone.

Comparison with PEDCo Study

The costs for the FGD systems described in the report by Hoffman-Muntner⁽⁶⁻¹⁾ are estimated from costs reported in a study by TVA.⁽⁶⁻³⁾ A more recent report by PEDCo⁽⁶⁻⁴⁾ indicates that the annualized costs of FGD are three to four times higher than those reported by TVA. The estimates reported by PEDCo are in 1980 dollars, but they have been adjusted for use here to 1977 dollars, using an adjustment factor of 7 percent per year. PEDCo estimates that the annualized cost of controlling SO₂ to 1.2 lbs/10⁶ Btu by the lime FGD process is \$0.73 per million Btu for a 500 MW capacity plant burning eastern 3.5 percent sulfur coal. This estimate does not include the cost of coal, which adds approximately \$0.84 per million Btu to the cost for a total of \$1.57 per billion Btu. This estimate of FGD is 11 percent higher than PEDCo's estimate of the cost of burning low-sulfur western coal without FGD as shown in Table 25. (PEDCo's adjusted estimate of the cost of low-sulfur western coal is equivalent to the estimate obtained from the figures reported in Coal Week⁽⁶⁻²⁾.)

PEDCo also estimated the cost of a combined system of physical coal cleaning and FGD. However, this estimate does not account for the direct and indirect benefits of burning clean coal. Table 26 compares the estimates by PEDCo and Hoffman-Muntner for both cases. For the combined FGD/PCC case, the annualized cost estimated by PEDCo includes \$0.57 per million Btu attributable to physical coal cleaning and \$0.60 per million Btu attributable to FGD. The total cost for the combined system is \$2.02/10⁶ Btu, including a

TABLE 25. RELATIVE ECONOMICS OF SULFUR REMOVAL TECHNOLOGIES BASED ON
ADJUSTED PEDCO ESTIMATES (6-4) (1977 dollars)

SO ₂ Control Technology	Eastern Coal, % Sulfur	Cost, \$/10 ⁶ Btu			
		SO ₂ Emission Standard, 1.2 lb/10 ⁶ Btu		SO ₂ Emission Standard, 0.5 lb/10 ⁶ Btu	
		Not Including Price of Coal	Including Price of Coal	Not Including Price of Coal	Including Price of Coal
FGD Alone (Lime)	3.5	0.73	1.57	--	--
PCC/FGD	3.5	1.18	2.02	1.56	2.40
Low-Sulfur Western Coal	--	--	1.41	--	--

TABLE 26. COMPARISON OF HOFFMAN-MUNTNER AND PEDCo COST ESTIMATES
FOR FGD AND COMBINED FGD/PCC^(a)
(does not include raw coal cost)

	PEDCo	Hoffman- Muntner
<u>FGD Alone</u>		
Total capital investment, \$/kW	\$101.98	\$59.08
Fixed costs, \$/10 ⁶ Btu	0.41	0.13
Operating and Maintenance, \$/10 ⁶ Btu	0.32	0.14
Total annualized costs, \$10 ⁶ Btu	0.73	0.27
<u>Combined PCC/FGD</u>		
PCC portion:		
Total capital investment, \$/kW	12.65	13.705
Fixed costs, \$/10 ⁶ Btu	0.13	0.025
Operating and maintenance, \$/10 ⁶ Btu	0.44	0.089
Total annualized costs, \$10 ⁶ Btu	0.57	0.114
FGD portion:		
Total capital investment, \$/kW	90.87	46.2
Fixed costs, \$/10 ⁶ Btu	0.36	0.103
Operating and maintenance, \$/10 ⁶ Btu	0.23	0.101
Total annualized costs, \$10 ⁶ Btu	0.60	0.204
Benefits with combined PCC/FGD, \$/10 ⁶ Btu:		
Increased heat content	--	0.029
Savings in coal transport costs	--	0.011
Savings in ash disposal costs	--	0.005
Savings in coal pulverizing costs	--	0.001
Savings in payments to trust fund	--	0.001
Maintenance savings	--	0.007
Total benefits included in study	--	0.054
Total net combined PCC/FGD costs, \$/10 ⁶ Btu	1.18	0.26

(a) Based on the following parameters:

Power plant capacity = 500 MWe

Coal sulfur level = 3.5 percent

SO₂ emission standard = 1.2 lb/10⁶ Btu

Amortization period = 15 years (Hoffman-Muntner)

Interest rate = 8 percent (Hoffman-Muntner)

Capital recovery factor = 18.75 percent (PEDCo)

Utilization factor for coal cleaning plant = 38.6 percent (Hoffman-Muntner)

Availability of FGD system = 80 percent (Hoffman-Muntner)

Capital recovery factor for FGD system = 15.55 percent (Hoffman-Muntner)

All costs in 1977 dollars.

charge of $\$0.84/10^6$ Btu for the raw coal. Although PEDCo concludes that the total cost for the combined system is higher than the cost for FGD alone, the cost of the combined system would be reduced significantly by incorporating the value of the benefits for using clean coal. This is illustrated by adding PEDCo's value for the cost of FGD in a combined system ($\$0.60/10^6$ Btu) to the cost of physical coal cleaning ($\$0.11/10^6$ Btu) estimated by Hoffman-Muntner for a similar case. Subtracting the value of the benefits estimated by Hoffman-Muntner reduces the total cost by $\$0.05/10^6$ Btu. The total cost ($\$1.50/10^6$ Btu--including $\$0.84/10^6$ for the cost of raw coal) is 7 percent higher than the estimates for low-sulfur western coal.

Best Values for Evaluation of Relative Total Direct Costs and Benefits

The difference in relative values in the cost of combined physical coal cleaning and FGD indicates the need for careful evaluation of all of the direct and indirect costs and benefits of utilizing physically cleaned coal. Therefore, Battelle reevaluated the combined physical coal cleaning and flue gas desulfurization control systems to consider additional benefits beyond those evaluated by Hoffman-Muntner. The estimate for the FGD system reported by PEDCo was adopted as a realistic investment cost. However, PEDCo reports that 89.1 percent of the investment required for a stand-alone FGD system is required for the FGD system when combined with PCC in contrast to the value of 78.2 percent used by Hoffman-Muntner. But, because the PEDCo factor is more recent, and they are believed more authoritative in FGD costing, their factor has been adopted. Therefore, the investment cost for the FGD portion listed in Table 27 (90.9 $\$/kW$) was obtained from the estimates by PEDCo. The fixed costs ($\$0.36/10^6$ Btu) were derived by applying the same factor. The operating and maintenance costs estimated by PEDCo ($\$0.23/10^6$ Btu) remain unchanged. The estimate of the total annualized costs for the FGD system is $\$0.59/10^6$ Btu.

The estimates of the required total capital investment for PCC were approximately the same ($\$13.705/kW$ by Hoffman-Muntner versus $\$12.65/kW$ by PEDCo). The Hoffman-Muntner estimate was selected as the representative figure and a capital recovery factor of 18.43 percent was applied to determine the fixed costs of $\$0.041/10^6$ Btu. The capital recovery factor includes a plant

TABLE 27. ADJUSTED ESTIMATE OF COSTS AND BENEFITS OF COMBINED PCC/FGD AND FGD SYSTEMS^(a)

<u>FGD Alone</u>	
Total capital investment, \$/kW	\$101.98
Fixed costs, \$/10 ⁶ Btu	0.41
Operating and maintenance, \$/10 ⁶ Btu	<u>0.32</u>
Total annualized costs, \$/10 ⁶ Btu	0.73
<u>Combined PCC/FGD</u>	
PCC portion ^(b) :	
Total capital investment, \$/kW	13.705
Fixed costs, \$/10 ⁶ Btu	0.041 ^(c)
Operating and maintenance, \$/10 ⁶ Btu	<u>0.089</u>
Total annualized costs, \$/10 ⁶ Btu	0.130 ^(d)
FGD Portion	
Total capital investment, \$/kW	90.9
Fixed costs, \$/10 ⁶ Btu	0.36 ^(e)
Operating and maintenance, \$/10 ⁶ Btu	<u>0.23^(e)</u>
Total annualized costs, \$/10 ⁶ Btu	0.59
Benefits with combined PCC/FGD, \$/10 ⁶ Btu:	
Increased heat content	0.029
Savings in coal transport	0.011
Savings in ash disposal	0.005
Savings in coal pulverizing costs	0.001
Savings in payments to trust fund	0.001
Maintenance savings	0.007
Crushing and screening cost savings	0.023
Stack gas reheat cost savings	0.014
Savings in derating power plant output (capacity)	<u>0.017</u>
Total net benefits	<u>0.108</u>
Total net cost of combined PCC/FGD, \$/10 ⁶ Btu	0.612

- (a) Based on the following parameters:
 Power plant operating capacity = 500 MWe
 Sulfur content of coal = 3.5 percent
 SO₂ emission standard = 1.2 lb/10⁶ Btu.
- (b) PCC costs are from Hoffman-Muntner study.
- (c) Capital recovery factor = 0.1843 (plant life = 10 years, interest = 13 percent).
- (d) Utilization factor for coal cleaning plant = 38.6 percent.
- (e) Costs calculated using percent of FGD alone developed by Hoffman-Muntner.

life of 10 years and an interest rate of 13 percent. The operating and maintenance costs of $\$0.089/10^6$ Btu were selected from the estimate by Hoffman-Muntner. The total annualized costs for the PCC system then are $\$0.13/10^6$ Btu. The annualized costs for both the PCC and FGD are $\$0.72/10^6$ Btu; however, the benefits derived from the improved quality of coal due to physically cleaned coal reduce this total figure. The easily defined monetary benefits attributed to the burning of cleaned coal are outlined as follows:

- (1) The increased heat content per ton of cleaned coal is reflected in a higher value of the coal per ton than raw coal.
- (2) Because of the higher heat content of the cleaned coal, less tonnage needs to be shipped for a given total heat value. Therefore, the shipping cost for clean coal is less.
- (3) The reduced ash content of clean coal reduces the ash disposal burden on the utility.
- (4) Less cleaned coal needs to be pulverized for a given heat value, which reduces the pulverizer costs. In addition, cleaning often eliminates the harder particles in the coal, thus reducing the maintenance on pulverizing equipment.
- (5) Because the number of tons of shipped coal is reduced, the amount paid to the Mine Operators Pension and Trust Fund is also reduced.
- (6) The use of a coal with reduced ash and sulfur content reduces the maintenance costs on the power plant.

Hoffman-Muntner evaluated these six items. Tables 26 and 27 indicate the cost savings for each area. The total of these benefits is $\$0.054/10^6$ Btu.

In addition to savings indicated by these areas, several other factors impact on the costs of the power plant and FGD system, as summarized here:

- (1) Raw coal which is not physically cleaned is normally crushed and screened to a size of 2 x 0 inches before sale to utility plants. With physically cleaned coal, the crushing and screening operations are integrated into the cleaning plant. The cost of the crushing and screening operation is $\$0.60/\text{ton}$ or $\$0.023/10^6$ Btu.

(2) Following FGD, the stack gas must be reheated to avoid downstream condensation and corrosion. Physically cleaned coal eliminates the need to process all of the flue gas through the FGD system to meet current environmental emissions standards. Therefore, the amount of gas which is not treated in the FGD system also does not have to be reheated, saving the energy expended in reheating. In addition, the sensible heat in the gas which bypasses the FGD system can be used as a source for reheating the treated gas.

(3) The power required by the FGD system reduces the amount available for sale by the utility, thus derating the power plant output. Treatment of a reduced quantity of stack gas due to burning physically clean coal reduces the amount of power required by the FGD system.

The sum of these additional benefits is $\$0.054/10^6$ Btu. Ignoring the obvious benefit from increased plant availability, the total net benefits due to physical coal cleaning are $\$0.108/10^6$ Btu. These benefits reduce the total cost of the combined system of PCC/FGD to $\$0.612/10^6$ Btu versus $\$0.73/10^6$ Btu for the stand-alone FGD system. The net cost for the combined system represents a savings of 18 percent over the cost of the FGD system alone. Including $\$0.84$ for the cost of raw coal, the net cost of the combined PCC/FGD system is $\$1.35/10^6$ Btu, which is 4 percent less than the cost of western low-sulfur coal.

Evaluation of System Performance

The availability of an individual power plant for the generation of electricity is dependent upon the reliability of the various components which make up the complete system. Thus, it is the objective of this report section to explore the influence of large component reliabilities on the cost of electricity generated and sold.

A baseloaded, single-unit station is used as a basis for the analysis and it is assumed that this baseloaded station provides the lowest cost

electricity for the utility in question. That is, it is assumed that the analysis can be performed on this single unit without introducing the complexity of its interactions with other units within the owner's utility grid or with outside utilities which may interchange power at a price or cost.

It is recognized that no completely valid analysis can be performed, however, without introducing this complexity. Thus, any results obtained or conclusions reached must be substantially qualified. The major difficulties accrue from the recognition that the assumption made carries with it additional postulates: (1) that all the net electricity produced can be marketed, and (2) that the capital investments in other parts of the utility grid can be ignored. Neither of these conditions is justifiable, but their influence on the final result should not be significant.

It is recognized further that any truly valid analysis of costs must be performed for a specific situation. In such a site-specific situation, the interactions not included here would be introduced. Despite all of these qualifications, however, this analysis should provide an excellent description of the methods to be used and approximate results to indicate the relative desirabilities of the various SO₂ emission control techniques, alone and in combination.

System Description

For purposes of the present analysis, a single-unit power plant having a nominal capacity of 500 MWe was selected. The total system being analyzed is shown diagrammatically in Figure 29.

Fuel alternatives are raw coal (high-sulfur), raw coal (low-sulfur), and cleaned high-sulfur coal. The high-sulfur coal would logically be eastern (Northern Appalachian) coal and the low-sulfur coal, western. Physical coal cleaning is postulated as an alternative control mechanism for use with the high-sulfur eastern coal.

With the boiler being fed with low-sulfur coal or with higher sulfur content coal that can be physically cleaned to meet SO₂ emission standards, the flue gas would bypass the desulfurization scrubbers and the reheater and

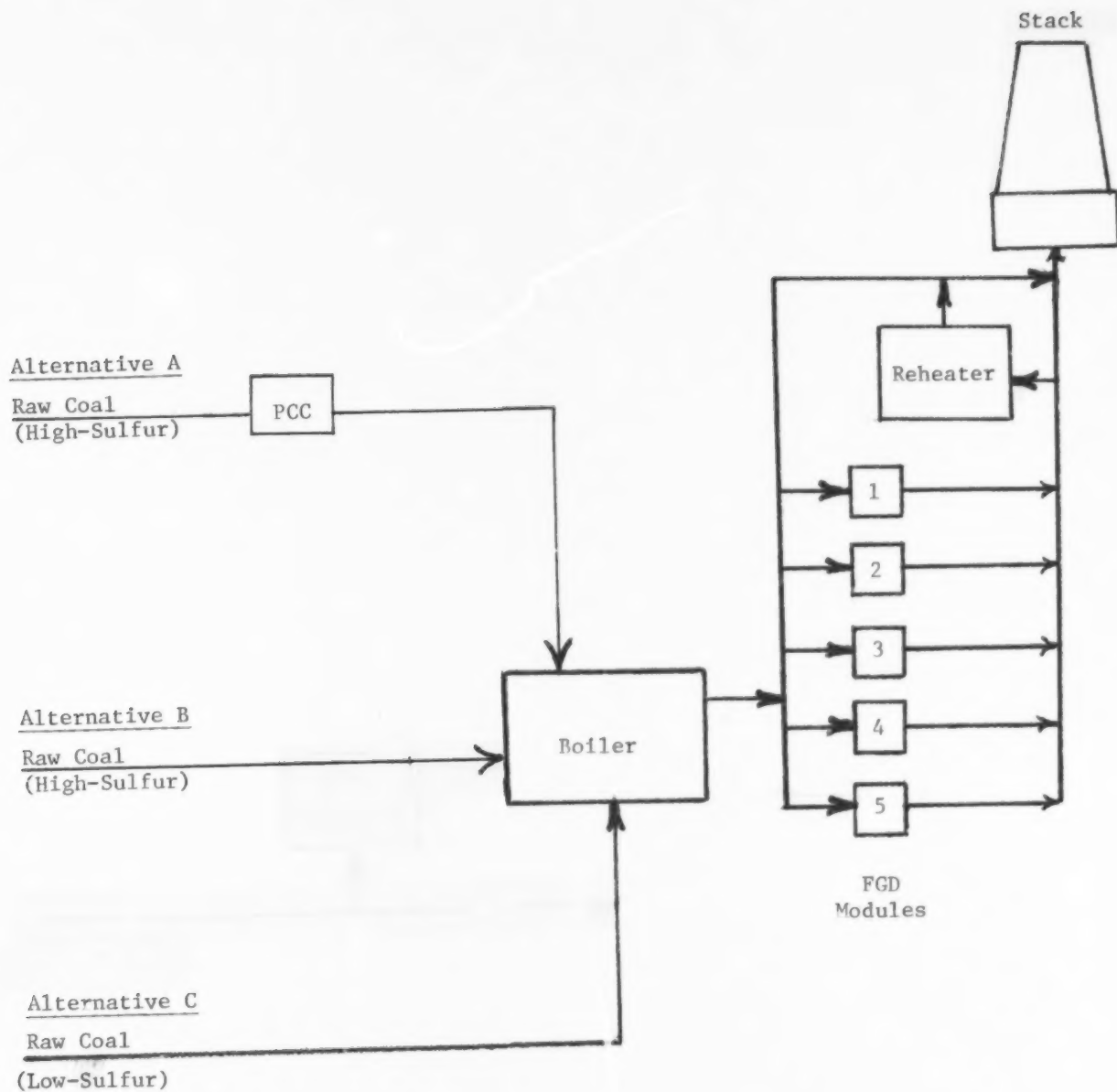


FIGURE 29. SIMPLIFIED DIAGRAM OF BOILER AND SO₂ CONTROL SYSTEM ALTERNATIVES UNDER ANALYSIS

go directly into the stack. With raw high-sulfur coal the scrubber modules and reheater would be utilized.

FGD systems are composed, normally, of several modules. A 500 MWe power plant requires four 125 MWe modules to meet the emissions standard with an FGD system only. One spare module is often provided so that greater system availability is achieved. With a combined control system of physical coal cleaning and FGD, three modules and one spare may be sufficient. For purposes of the present analysis, this latter arrangement is postulated to treat 80 percent of the stack gas.

System Availability

Inasmuch as costs for generating electricity are greatly dependent, not only upon the system type and design, but also upon its availability and use, it is important to evaluate its availability. Other aspects of the system are either not subject to great variability for a specific site or situation (system type and design) or subject to control (the amount of use). Thus, a "standard" coal-fired steam turbine system is postulated; this unit will be "baseloaded" to the extent that its availability permits.

In evaluating the availability of a generating system to produce electricity, several points must be considered. Many smaller components, either because they are redundant or so reliable, do not enter into any evaluation of availability. The availability of the coal cleaning facility also does not have an influence because a coal storage pile is always provided to permit the power generating facility to operate even when the coal cleaning facility is not running. Thus, the units of concern are the boiler and the FGD modules. And in the analysis, for purposes of simplification, the boiler availability is considered to include any influence of outages of the pulverizers, electrostatic precipitators, stack, etc.

In assessing the availability of the simplified system, the boiler and the FGD subsystem are in series. The overall availability, in this case, is the product of the individual availabilities. The computation of the availability of the FGD subsystem, consisting of a number of partial-load modules in parallel, is more complex.

FGD Subsystem Availability. Ignoring for the moment the influence of boiler availability on overall availability, the availability, A, of the overall power generating system as represented by the FGD subsystem availability, is calculated by the relationship,

$$A = \frac{G}{C}$$

where G = average power generated

C = generating capacity = 500 MWe .

Average power generated, G, is calculated by determining the power which would be generated for each level of FGD module failure, multiplying by the probability of the appropriate number of FGD module failures in each case, and summing the results to obtain the statistically expected level of power generated. The average power generated would tend to approach this expected level over an extended period of time such as one or more years.

For purposes of the analysis, it is postulated that the 500 MWe power plant requires 4 operating FGD modules to meet the emission standard, without coal cleaning, and that if fewer FGD modules are operating at any given time, the generated power would have to be reduced proportionately to meet the emission standard. With coal cleaning, it is estimated that only 3 operating FGD modules are required.

An example illustrates this approach. It is first necessary to define additional terms.

Let F = probability of a given FGD module being inoperative at any given time

X_j = probability of exactly j FGD modules being inoperative at any given time

N = total number of FGD modules

p = number of primary FGD modules

s = number of spare FGD modules

$P(\cdot)$ = probability of event ($\cdot$), e.g., $P(SSII)$ = probability of first 2 FGD modules operating successfully and last 2 being inoperative at any given time (where S denotes successful operation and I denotes an inoperative or failure condition)

When $N = 4$:

$$X_0 = P(SSSS) = (1-F)^4$$

$$X_1 = P(ISSS) + P(SISS) + P(SSIS) + P(SSSI) = 4F(1-F)^3$$

$$X_2 = P(IISS) + P(ISIS) + P(ISSI) + P(SIIS) + P(SISI) + P(SSII) = 6F^2(1-F)^2$$

$$X_3 = P(IIIS) + P(IISI) + P(ISII) + P(SIII) = 4F^3(1-F)$$

$$X_4 = P(IIII) = F^4$$

When $N = 5$, X_j 's can be shown by the same approach to be:

$$X_0 = (1-F)^5$$

$$X_1 = 5F(1-F)^4$$

$$X_2 = 10F^2(1-F)^3$$

$$X_3 = 10F^3(1-F)^2$$

$$X_4 = 5F^4(1-F)$$

$$X_5 = F^5$$

For the case where FGD alone is the emission control strategy, a total of 5 FGD modules would be used (4 primary and 1 spare).

Then,

$$G = 500(X_0 + X_1) + 3/4(500)X_2 + 1/2(500)X_3 + 1/4(500)X_4 + (0)X_5$$

In the first term, the sum of the probabilities of 0 and 1 FGD module failures is multiplied times 500 MWe because full power would be generated with either 0 or 1 FGD module failures because of the 1 spare. In the second term, the probability of 2 FGD module failures is multiplied times $3/4 \times 500$ MWe, because the power generated would have to be reduced to $3/4$ of full power with only 3 FGD modules operating out of the required 4. The remainder of the terms follow the same logic. Calculated FGD subsystem availabilities are as shown in Table 28. Module availabilities 0.5, 0.65, 0.75, and 0.9 were selected as being representative of current experience.

Influence of Boiler Availability on Overall Availability. As previously indicated, for subsystems joined in a series configuration, the overall availability of the system is the product of the individual availabilities.

TABLE 28. CALCULATED PERFORMANCE OF FGD
SUBSYSTEMS, OVERALL AVAILABILITY
(Fraction of Time)

Fuel (with FGD)	p ^(a)	s ^(b)	FGD Individual Module Availability			
			0.50	0.65	0.75	0.90
Raw coal	4	1	0.617	0.784	0.878	0.977
Cleaned coal	3	1	0.646	0.807	0.895	0.981
Cleaned coal	3	2	0.760	0.902	0.960	0.997

(a) p = number of primary FGD modules

(b) s = number of spare FGD modules

Thus, in the system under consideration, the overall availability is the product of the boiler availability and that of the FGD subsystem. Resulting availabilities for the total system are shown in Table 29 for boiler availabilities of 0.8 and 0.9 combined with the FGD subsystem availabilities previously presented in Table 28.

Postulated System Availabilities to Be Used for Cost Analysis. Before costs may be computed, it is necessary to select an appropriate set of availabilities from Table 29 to match a postulated set of fuels and system configurations. The postulated set of fuels and system configurations are derived from the previous system description associated with Figure 29.

Six combinations are defined; these are shown in Table 30. The basis for the postulated conditions of availability is discussed in the following paragraphs.

In the selection or determination of appropriate values for availabilities of generation systems, the most logical approach is to base the selection on historical, statistical information. Unfortunately, however, historical, statistical information is not available to the extent required. Only now, at the present, are studies being initiated to provide the sound basis needed to document values for availability of these systems. Thus, the only alternative is to make qualitative projections on the basis of a few numbers,

TABLE 29. POSTULATED CONDITIONS OF AVAILABILITY
(Fraction of Time)

1. Raw (high-sulfur eastern) coal (no FGD) (baseline)	0.8
2. Raw (low-sulfur western) coal (no FGD)	0.7
3. Cleaned (high-sulfur eastern) coal (no FGD)	0.9
4. Raw (high-sulfur eastern) coal with FGD ($p = 4, s = 1$) ^(a) (Boiler = 0.8; FGD = 0.65/module)	0.627
5. Cleaned (high-sulfur eastern) coal with FGD ($p = 3, s = 1$) ^(a) (Boiler = 0.9; FGD = 0.75/module)	0.806
6. Cleaned (high-sulfur eastern) coal with FGD ($p = 3, s = 2$) ^(a) (Boiler = 0.9; FGD = 0.75/module)	0.864

(a) p = number of primary FGD modules; s = number of spare FGD modules.

industry opinions, and engineering judgement. And, if the development used here does not satisfy the individual reader, he is free to develop his own consistent set of availability values.

Boiler availability, of course, is dependent upon the design philosophy used and how well the erectors were able to implement the design. Coal quality is also an important factor in operations. It is well recognized by the industry that a well-designed and well-executed boiler that considers the quality of the coal which will be fired will have a high degree of availability.

Many well-maintained boilers in the utility industry firing the raw coal for which they were designed achieve an availability factor of about 0.8. This value was selected for use in this analysis.

When coals of different qualities and characteristics are used, boiler availability factors differ. It is well known in the industry that using low-sulfur western coals in boilers designed and equipped for eastern coals results in a degradation of the availability factor. For this study, a value of 0.7 is taken as the availability factor representing this situation.

TABLE 30. SUMMARY OF COSTS FOR POWER GENERATION USING VARIOUS CONTROL MODES

Number	Case Description	Emission Regulations Met	Operating Hours per Year (b)	Power Plant Costs, ¢/kWh			FGD Costs, ¢/kWh	Coal Cleaning Costs and Savings, ¢/kWh			Total Costs, ¢/kWh			
				Fixed	Fuel	Production		Incremental Maintenance	Fixed	O&M		PCC Savings		
													PCC	PCF/FGD Savings
1 (a)	Raw high-sulfur eastern coal, no FGD (baseline)	None	7008	1.446	0.840	0.148	0.093	--	--	--	--	2.527		
2	Raw low-sulfur western coal, no FGD	NSPS (e)	6132	1.652	1.410	0.248	--	--	--	--	--	3.310		
3 (a)	Cleaned high-sulfur eastern coal, no FGD	Various SIP's	7884	1.285	0.898	0.158	0.015	--	0.041	0.089	-0.041	2.445		
4	Raw high-sulfur eastern coal, with FGD (4 modules + 1 spare) (Boiler = 0.8, FGD = 0.65/module)	NSPS (f)	5493	1.845	0.840	0.148	0.093	0.389	0.230	--	--	3.545		
5	Cleaned high-sulfur eastern coal, with FGD (3 modules + 1 spare) (Boiler = 0.9, FGD = 0.75/module)	NSPS (f)	7061	1.435	0.898	0.158	0.015	0.270	0.230	0.046	0.089	-0.031	3.069	
6	Cleaned high-sulfur eastern coal, with FGD (3 modules + 2 spares) (Boiler = 0.9, FGD = 0.75/module)	NSPS (f)	7569	1.339	0.898	0.158	0.015	0.282	0.230	0.043	0.089	-0.041	-0.031	2.982

(a) Not in compliance with NSPS promulgated December 23, 1971 (36FR24876).

(b) Based on Table 29.

(c) Operation and maintenance.

(d) p = number of primary FGD modules; s = number of spare FGD modules.

(e) [Same as (c) Table 1, p. 10].

(f) [Same as (d) Table 1, p. 10]... Kilgroe (6-12).

Conversely, the availability factor is higher when higher quality coal, particularly when cleaned coal, is used in boilers designed for raw coal. Discussions with operators who have switched to cleaned coal indicate that a significant improvement in boiler availability is achieved. A factor of 0.9 was selected to represent this situation.

Recent performance of well-maintained FGD systems indicates an overall availability of 0.75 to 0.80 is being achieved.⁽⁶⁻⁵⁾ In Table 28, for raw coal as fuel and one spare FGD module, this approximately corresponds (0.784) to a nominal individual FGD module availability of 0.65. If cleaned coal is used as fuel, individual module availabilities increase because of lower inlet sulfur dioxide levels to the scrubbers and lower particulate levels. An individual module availability of 0.75 was selected to represent the cases for FGD used with cleaned coal as fuel.

The composite availabilities based on these individual availabilities defined above are presented in Table 29. They are used in the determination of some of the individual components of cost shown in a later section.

System Costs

Costs associated with the production of electrical power include those for facilities, fuel, and operation and maintenance. For overall costs, or costs per kilowatt-hour, to be estimated, each of the cost components and its basis must be accurately defined. It is the purpose of this report section to provide this definition.

Power Plant Costs

The capital costs of coal-fired power plants vary considerably with design, location, and many factors, so that it is always difficult to provide a numerical value for this cost which is convincing to all readers. However, a competent study⁽⁶⁻⁶⁾ was performed in 1972 which provided detailed cost analysis of a hypothetical coal-fired facility; these costs were developed to permit valid comparisons with similar costs for other types of power generating facilities.

The base construction cost of a 1000 MWe electric (coal-fired) generating plant was reported as:

\$174,115,200 (January, 1971, dollars and prices)

not including normal contingency allowances. Use of this information for projection to any later operating date would require adjustment for escalation. In any real situation, also, allowance for interest during construction would also be necessary.

On the basis of previous work in cost analysis of power plants⁽⁶⁻⁷⁾, it was estimated that the exponent on size ratio for relating costs is about 0.8. Thus, the base construction cost of a 500 MWe electric (coal-fired) generating plant would be:

$$\left(\frac{500}{1000}\right)^{0.8} (\$174,115,200) = 0.574 (\$174,115,200) =$$

$$= \$99,942,125 \text{ or}$$

$$= \$199.88/\text{kW} .$$

For a power plant for which the construction decision was made in January, 1971, the estimated^(a) total investment in the physical facility would be:

Base construction cost (in January 1971 dollars)	\$199.88/kW
Contingency and spare parts allowance (12%)	<u>23.99</u>
Total direct costs	\$223.87/kW
Interest during construction (at 10% per year)	<u>104.32</u>
Total plant cost (no escalation)	\$328.19
Escalation during construction ^(b)	<u>102.56</u>
Total plant cost at commercial operation	\$430.75/kW

Thus, the total capital investment for a (500 MWe) generating plant starting operations July, 1977 (6-1/2 years after January, 1971) would be as indicated.

- (a) The procedure follows that of Reference 6-8, Tables 1-3, page 18, with adjustments made for higher interest and escalation rates.
- (b) A construction schedule of 6-1/2 years is indicated by Reference 6-8, Tables 1-3, page 18 for a coal-fired plant. Escalation rates averaged 10% per year between January, 1971, and July, 1977, the postulated period of construction. Data for construction cost increases were taken from Reference 6-9, Table 62 S.

The investment for later start-up dates would be still higher because of longer periods and higher rates of inflation and higher interest rates.

Annualized costs of capital investment dependent charges (i.e., fixed charges) are a function of many items, such as geographical location, debt-equity ratio for the utility, profitability, bond rating, etc.

Annual capital (fixed) charges include: depreciation, interim replacements, insurance, interest and debt equity return, Federal and state income taxes, and local property and equipment taxes. Although the contributions of each of these to the annual capital (fixed) charges may vary as a function of the above items, it is possible to estimate each on some average or typical basis. This was done by TVA⁽⁶⁻³⁾ for an analysis of FGD costs. With slight modifications to account for current interest rates, annual capital charges for power industry financing were shown as follows:

	As percentage of original investment for 30 years remaining life
Depreciation - straight line	3.33
Interim replacements (equipment having less than 30-year life)	0.67
Insurance	0.50
Total rate applied to original investment	4.50

	As percentage of outstanding depreciation base ^(a)
Cost of capital (capital structure assumed to be 50% debt and 50% equity):	
Bonds at 11% interest	5.50
Equity at 12% return to stockholder	6.00
Taxes:	
Federal (50% of gross return or same as return on equity)	6.00
State (national average for states in relation to Federal rates)	4.80
Total rate applied to depreciation base	22.30

(a) Original investment yet to be recovered or "written off".

Using the above values, a capital recovery factor (CRF) can be computed. For a period of 30 years with a total return rate of 22.30 percent, the CRF would be 22.353 percent. To this must be added amounts of 0.67 percent for interim replacements and 0.50 percent for insurance. The total percentage of 22.353 plus 0.67 plus 0.50 or 23.523 percent is then applied to the total capital investment to obtain the annual fixed charge. The 500 MWe plant cost is \$215,375,000 (500,000 kW x \$430.75/kW), as previously estimated.

Fuel Costs

Raw coal costs (for eastern coal) used in previous sections of this report were \$0.84/10⁶ Btu; this value is used here. This compares with costs of \$0.79/10⁶ Btu (W. Ky. 12), \$0.88/10⁶ Btu (W. Ky. 9), and \$1.06/10⁶ Btu (W. Ky. 11) used in a recent TVA analysis.⁽⁶⁻¹⁰⁾

Production Costs

In the TVA analysis⁽⁶⁻¹⁰⁾ just referenced, production cost was computed on the basis of its being a percentage of the fuel cost. Fuel cost was taken as 85 percent of the overall production cost. Therefore, the incremental production cost would be 15/85 or 17.6 percent of the fuel cost.

Incremental Maintenance Costs

In addition to the normal maintenance costs which are included as a part of the production costs just discussed, for coals with high ash and sulfur contents, Phillips and Cole⁽⁶⁻¹¹⁾ found that there is an incremental maintenance cost. This incremental maintenance cost increases at a rate of \$0.15/(ton of coal)(percent of ash-plus-sulfur in excess of 12.5 percent). Thus, for a coal for an ash-plus-sulfur content of 26.43 percent, the incremental maintenance cost would be \$2.09/ton of coal burned. Costs included here are those such as costs due to higher pulverizer wear, higher boiler tube wastage, and throat plugging.

FGD Costs

Costs for FGD appear in Tables 26 and 27 of this section. In Table 26, the capital cost of the FGD system is shown, as estimated by PEDCo⁽⁶⁻⁴⁾, to be \$90.87/kW for five modules, four operating and one spare. For four modules, three operating plus one spare, PEDCo⁽⁶⁻⁴⁾ estimated the cost to be (0.891) (\$90.87) or \$80.97/kW. Thus, the costs for a 500 MWe facility would be:

Five modules	\$45,435,000.
Four modules	\$40,485,000.

Annual fixed charges are computed by applying the previously determined cost recovery factor of 23.523 percent to these capital investments.

Operating and maintenance costs (see Table 27) are computed to be

$$\$0.23/10^6 \text{ Btu} .$$

Fixed costs will, of course, vary as a function of use, but operating and maintenance costs (per 10^6 Btu) should remain constant for reasonably small variations in availability and sulfur removal quantities.

Physical Coal Cleaning Costs

Investment costs for physical coal cleaning facilities as determined by Hoffman-Muntner⁽⁶⁻¹⁾ are \$13.705/kW (see Table 27). For a facility to supply a 500 MWe power generation plant, the total capital investment would be

$$\$6,852,500 .$$

Annual fixed charges would be 23.523 percent of this value.

Operations and maintenance charges are shown in Table 27 to be \$0.089/ 10^6 Btu. In the same table, benefits resulting from the use of coal cleaning are defined and evaluated. Direct cost savings resulting from coal cleaning are

Savings from coal transport	\$0.011/10 ⁶ Btu
Savings in ash disposal	0.005
Savings in coal pulverizing cost	0.001
Savings in payments to trust fund	0.001
Savings in crushing and screening	<u>0.023</u>
Total	\$0.041/10 ⁶ Btu.

The items of increased heat content and maintenance savings are being accounted for in a different manner.

When used in conjunction with a flue gas desulfurization system, coal cleaning will result in the additional savings of

Savings in stack gas reheat	\$0.014/10 ⁶ Btu
Savings from a lower derating of power plant output	<u>0.017</u>
	\$0.031/10 ⁶ Btu.

Systems Performance and Costs

Utilizing the developed systems performances and systems costs, a summary of costs for the generation of electrical power is presented in Table 30. In the preparation of this table, the hours of operation per year were based on the postulated availabilities of Table 29 and the costs were computed using the values and methods just discussed.

For those readers who find some fault with any of the values used or assumptions made, it should be a simple matter for them to use their own assumptions and values and, being careful to be completely consistent, arrive at their own results. As was previously pointed out, each analysis of this type really needs to be developed in terms of a specific situation. In this way, the real benefits and penalties to a specific utility system or to a specific generating unit can be accurately and unambiguously developed.

Discussion and Conclusions

Each of the exhibits and methodologies presented in this report section were developed to show that, when all costs and benefits to utilities of using physical coal cleaning are properly evaluated, a definite economic superiority for physical coal cleaning exists, even if supplemental application of another method, FGD, must be used to achieve full compliance with applicable 1971 New Source Performance Standards (NSPS) or State Implementation Plan (SIP) emission limits.

Inspection of the total cost column of Table 30 reveals some interesting specific points. First of all, the systems which include coal cleaning provide the least cost methods of producing electricity. Comparison of the two systems not providing sufficient control to meet the 1971 New Source Performance Standards (Cases 1 and 3) shows that physical coal cleaning of the fuel provides for an overall lower cost of generation, about 2.4¢/kWh versus about 2.5¢/kWh, than does the use of raw coal. This is despite the cleaning costs and the loss of some Btu's, because of the greater, more efficient utilization of the generation facility and a consequent lower fixed charge per kWh generated.

Second, for the systems which achieve full compliance with NSPS, the two cases which incorporate physical coal cleaning with FGD are by far more economical, about 3.0¢/kWh in both Cases 5 and 6, than the about 3.5¢/kWh in Case 3 for FGD alone.

Finally, the example shown for the use of low-sulfur western coal (Case 2) indicates no cost benefit in comparison with any other case except Case 4, the one for FGD not in combination with physical coal cleaning. The cost here is about 3.3¢/kWh for Case 2 versus about 3.5¢/kWh for Case 4. This result tends to confirm the conclusion made by some utilities that the use of low-sulfur western coal to achieve compliance with NSPS is less costly than the use of FGD.

In summary, the combined use of physical coal cleaning with FGD is significantly more attractive economically in the examples presented than either FGD alone or western low-sulfur coal. It is very evident, also, that in any case where physical coal cleaning alone can provide compliance with

NSPS or with State Implementation Plans, its use will provide the lowest cost solution. However, in any specific case, the comparisons must be evaluated independently to account for site-specific variables such as coal composition, transportation requirements, and plant utilization.

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SECTION 7

ENVIRONMENTAL IMPACTS OF SULFUR REMOVAL STRATEGIES

Introduction

Environmental legislation throughout the United States has imposed severe restrictions on sulfur oxide emissions from power plants. Fundamentally, there are three ways of complying with these laws. First, the fuel can be prepared by removing sulfur before combustion so as to permit meeting emission standards; second, a high-sulfur fuel can be burned with sufficient removal of sulfur oxides from the flue gases; or third, a naturally occurring low-sulfur fuel can be used.

This section will assess the environmental impacts of the above control strategies for large combustion units burning coal. Specifically, the methods examined are physical coal cleaning, flue gas desulfurization, and the utilization of naturally occurring low-sulfur coal. The environmental benefits and penalties of each strategy are assessed, with the exception of sulfur oxide emission reduction, which is assumed to be fixed by the sulfur emission limit. It should be observed that the three strategies are not alternatives inasmuch as each strategy is not a complete system for providing fuel, controlling sulfur, and disposing waste.

Physical Coal Cleaning

Physical coal cleaning (or coal preparation) is largely a mechanical process, involving a series of crushing, sizing, separating, and drying steps. The pollutants associated with coal cleaning are primarily inorganic compounds associated with the ash fraction. Although lists of potential pollutants from coal cleaning and utilization containing hundreds of entries have been proposed, a group of 51 elements and 23 substances or groups of substances has been selected judgements as being the only ones of concern in physical

coal cleaning processes⁽⁷⁻¹⁾. These pollutants include those contained in solid waste, contaminated water, particulates, and gaseous emissions. Control methods are currently available for mitigating the effects of the majority of these pollutants.

In the following discussion, the potential pollutants and control methods for various coal preparation operations are briefly described.

Air Pollution and Control

Potential Pollutants. Air pollution associated with coal cleaning plant operations consists primarily of particulate emissions, including (1) fugitive dust from dry processes such as crushing, screening, and air cleaning; from bulk handling of coal and coal waste; and from transportation and storage; and (2) particulate emissions from thermal drying and from uncontrolled refuse pile fires. There are also gaseous emissions from thermal drying and from burning waste piles⁽⁷⁻¹⁾.

Typically, crushing and sizing operations produce dry, small particulates (0.5 to 6.0 μm) at ambient temperatures. The quantity of dust generated depends on the coal type, moisture level, and type of sizing and screening operations. In pneumatic cleaning operations, high concentrations of dry particulates (~ 120 gr/dscf) are generated with particle sizes up to 100 M. Thermal drying operations also produce high concentrations of particulate emissions (50 to 200 gr/dscf) in gas streams having high moisture levels and temperatures above 200 F. Furthermore, combustion gases containing SO_2 , NO_x , and CO, produced from the thermal dryers, will accompany the particulates. However, the concentrations of these gaseous emissions in the drying air stream are low compared with the particulate concentrations; also the concentrations of these gaseous combustion products are well within the performance standards required of new coal-fired power plants^(7-1,7-2).

The principal air pollutant from the transportation, storage, and handling of coal is fugitive coal dust. It is estimated that about 80 pounds of coal per ton hauled is lost as fugitive dust during transit and at loading-unloading operations⁽⁷⁻³⁾. Long, open conveyor belts carrying dry material can be a significant source of dust along with all drop points onto or off of the conveyors. Open storage piles also generate dust, the amount generated depending on such factors as climate, topography, and characteristics of the

stored coal. Moreover, exhaust gases from moving vehicles for coal transportation and gaseous emissions from burning storage piles may be problems under certain circumstances⁽⁷⁻¹⁾.

Control Methods. Several types of air pollution control devices are available for application to coal cleaning operations. Particulate control devices may be broadly classified as dry inertial collectors (gravity settlers and cyclones), filters, and wet scrubbers. Control devices for the removal of gases or vapors involve absorption or adsorption in a variety of contacting devices. Fugitive dust emissions from coal storage, transportation, and handling operations can be controlled by water spraying, dust proofing, wind screens, and enclosures. The spontaneous combustion of coal piles can be prevented by proper compacting and sealing^(7-1,7-2).

The most difficult air pollution problem is the control of emissions from thermal dryers. For most thermal dryers, the initial air pollution control device is a cyclone collector. However, because the gaseous emissions from the primary collector frequently contain dust concentrations as high as 10 grains per actual cubic foot, a high efficiency secondary collector (usually a wet scrubber) is added at most coal cleaning plants⁽⁷⁻⁴⁾. Furthermore, wet scrubbers appear to provide some control of SO₂ emissions as well as particulates from thermal dryers⁽⁷⁻²⁾.

Table 31 summarizes the types and applications of currently available emission control devices.

Water Pollution and Control

Potential Pollutants. Contaminated water effluents associated with coal cleaning operations have three major sources: (1) preparation plant process water, (2) acid water drainage from coal waste deposits, and (3) similar contaminated drainage from coal storage piles.

The characteristics of process water are dependent upon the characteristics of the coal being processed and the particular process or recovery technique utilized in the operation. Generally, the principal pollutant present is suspended solids. Some minerals are also present as dissolved solids. Moreover, a study by the U.S. EPA⁽⁷⁻⁵⁾ analyzed untreated process

TABLE 31. CLASSIFICATION OF AIR
EMISSION CONTROL DEVICES

Particulates	Gases and Odors	Fugitive Emissions
Dry Inertial Collectors	Dry Adsorbers	Water Spraying
Gravity Settling Chambers	Wet Adsorbers	Dust Proofing
Cyclones		Oil
Fabric Filters		Calcium Chloride
Wet Inertial Scrubbers		Enclosures
Impingement		
Centrifugal		
Venturi		
Self-Induced		

water from several typical coal preparation facilities. The results of that study demonstrate that process water is slightly alkaline and contains large amounts of suspended and dissolved solids. The total suspended solids include both organic materials (tar, fine coal, grease, and oil) and inorganic materials (fine clay, sand, silt, and other mineral particulates), while total dissolved solids potentially may include all ions derivable from the mineral matter in the coal.

Acid drainage from coal waste deposits and coal storage piles leads to one of the most serious and complex water pollution problems. Acid drainage is produced when iron sulfides are exposed to air and water. The sulfur is oxidized to sulfuric acid, and the iron is solubilized as iron sulfate. Moreover, drainage from coal waste deposits frequently contains other pollutants. For example, in 1974, the U.S. EPA⁽⁷⁻⁶⁾ sampled several coal refuse piles to determine potential pollutants. The major water pollution hazards were found to be silt, heavy metals, and acid. In addition, substantial amounts of sodium, aluminum, magnesium, calcium, manganese, iron, zinc, copper, lead, and nickel were present in many samples. A wide range of acidities was also found because of varying sulfur levels in the raw coal. Furthermore, the concentration and total quantity of pollutants were found to be related to the degree of compaction of the refuse, the angle of side slopes, the extent of surface water control, the extent of use of surface coatings such as oil or salts, and the coal composition as related to the basic geologic formation from which the coal originated.

Acid drainage is further discussed under solid waste pollution.

Control Methods. The most effective method for minimizing process water production is to recover the coal and other reusable materials from the waste stream. Moreover, recirculation and treatment of wash water have become integral parts of the operation of a modern coal cleaning plant. With the use of water clarification methods (mechanical dewatering and sedimentation) a preparation plant can complete a closed-water circuit^(7-1,7-2,7-7). However, water clarification handles only suspended solids. Some waste streams may contain large amounts of dissolved solids or chemicals requiring further treatment. Current methods of removal or detoxification of these materials include neutralization, aeration, chemical oxidation or reduction, flotation,

and emulsion breaking. Ion exchange and reverse osmosis^(7-1,7-2) are not currently in use for this purpose.

Several methods are available to control acid drainage: (a) prevention of acid formation at the source (through using burial, alone or combinations of such techniques as compaction, covering, channeling, in situ chemical treatment, and/or vegetating); (b) neutralization of the acid as it forms (with alkaline neutralizers); and (c) disposal (in impoundments or deep aquifers)⁽⁷⁻¹⁾. Furthermore, at present, researchers are investigating a host of surface sealants, including gypsum, wood chips, fly ash, waste cements, and various types of vegetation with earth coverings to promote stabilization and control of refuse piles⁽⁷⁻⁶⁾.

Table 32 summarizes the available water pollution control methods.

Solid Waste Pollution and Control

Potential Pollutants. Solid waste is the largest single source of potential pollution from coal preparation plants⁽⁷⁻¹⁾. The detrimental effects from the unsatisfactory disposal of coal refuse include: (a) unsightly blight of the landscape, (b) production of silt and acid drainage, (c) air pollution resulting from accidental or spontaneous combustion of refuse, and (d) destruction of local vegetation and wildlife. In addition, conditions hazardous to human health may exist within the area affected by the refuse pile⁽⁷⁻⁸⁾.

As previously discussed, acid drainage from coal waste deposits may lead to a serious water pollution problem. Typically, 1.5 to 2 pounds of acid and 0.5 to 0.7 pounds of soluble iron are produced per acre of refuse surface per day; however, in some highly mineralized areas, acid has formed at a rate of more than 300 pounds per acre per day⁽⁷⁻⁹⁾. However, drainage from western coal wastes is usually nonacidic. There, the dominant water contaminants are calcium, magnesium, and sodium. In addition, only low concentrations of iron and sulfates result because the pyrite content is low in western coal⁽⁷⁻¹⁰⁾. Furthermore, because the annual precipitation in western coal fields is generally also low, the chances for significant drainage of water through waste materials are remote⁽⁷⁻²⁾.

Air emissions can result from the spontaneous combustion of coal refuse piles when air is allowed to circulate through the waste pile. The oxidation of the residual coal or other mineral matter in coal refuse piles can produce sufficient heat in comparison with heat dissipation rates⁽⁷⁻¹¹⁾. These

TABLE 32. CLASSIFICATION OF WATER TREATMENT
METHODS USED WITH COAL CLEANING
FACILITIES

Control of Suspended Materials	Control of Dissolved Materials	Acid Drainage Control
Mechanical Dewatering:	Neutralization	Prevention:
Centrifuges	Aeration	Burial
Cyclones	Chemical Oxidation	Compaction
Screens	Flotation	Covering
Filters	Emulsion Breaking	Channeling
Sedimentation:	Ion Exchange ^(a)	Chemical Treatment
Settling Ponds	Reverse Osmosis ^(a)	Vegetation
Sedimentation Tanks		Neutralization:
Flocculation		Alkaline Neutralization
Flotation		Reverse Osmosis ^(a)
		Freezing ^(a)
		Electrodialysis ^(a)
		Disposal:
		Impoundments
		Deep Aquifers

(a) Not currently being applied because of excessive cost.

burning wastes emit fumes including carbon monoxide, sulfur oxides, and hydrocarbons. In addition, burning refuse piles may convert trace elements in the coal refuse into a gaseous product. In particular, elements such as Hg, As, Cd, Se, Pb, Be, Na, Co, Cu, and V⁽⁷⁻¹²⁾ are most likely to be volatilized. Fortunately, however, condensation of these elements generally occurs in cooler parts of the waste piles prior to their escape to the atmosphere. Some waste piles have been burning continuously for more than 200 years, and approximately 300 coal waste piles are still burning⁽⁷⁻⁹⁾. As of 1968, it was estimated that the total load of contaminants originating from all burning coal wastes in the U.S. was only approximately 1 percent of the national total of air pollution; it would be even lower today; however, coal refuse pollutants are highly concentrated in the vicinity of the sources, where they can have considerable local impact⁽⁷⁻¹³⁾.

Control Methods. The best overall practice of environmental control for coal refuse disposal areas is to prevent acid formation or fire by proper construction and maintenance of the refuse piles. In addition to those control methods previously discussed (see control methods for air and water pollution), serious consideration is being given to utilizing coal refuse as a raw material. These uses include those for landfilling, road construction, building materials, sulfur compound manufacturing, and production of heat. Disposal areas also can be controlled and prepared for alternative uses by utilizing the following sequential reclamation technique: contouring, soil stabilization, soil conditioning, and revegetation^(7-1,7-2).

Noise Pollution and Control

Potential Effects. A coal preparation plant is usually a multistory building, often covered with corrugated sheet metal. Internally, the floor layout in combination with the placement of equipment can allow relatively free passage of sound at all levels. This "openness" and reverberant nature of the building, and the fact that there are multiple noise sources throughout the plant, may result in diffused noise permeating the entire building. Furthermore, local areas of higher noise can exist in close proximity to sources generating the noise⁽⁷⁻¹⁴⁾.

Typical noise levels in a coal preparation plant can span a wide range. For example, workers spending an 8-hour shift in a remote control room might be exposed to noise levels only on the order of 80 dbA (A-weighted decibels). On the other hand, workers in other plant areas may be exposed to ranges as high as 100 to 112 dbA⁽⁷⁻¹⁴⁾.

Permissible noise exposures for plant personnel under the Federal Coal Mine Health and Safety Act of 1969 (Public Law 91-173) are shown in Table 33.

TABLE 33. PERMISSIBLE NOISE EXPOSURE
(ACCORDING TO PUBLIC LAW
91-173)

Duration (hr/day)	8	6	4	3	2	1-1/2	1	1/2	1/4 or less
Permissible Sound Level (dbA)	90	92	95	97	100	102	105	110	115

Control Methods. Noise control measures for various items of equipment commonly found in coal preparation plants are listed in Table 34, along with associated potential problems in application. Rotation of work assignments and/or ear-protective devices may be used where these control measures cannot be implemented. Moreover, for any given plant, the most cost-effective overall noise control approach is likely to consist of a mix of machinery-related noise reduction and worker-related exposure control⁽⁷⁻¹⁵⁾.

Noise intruding into communities from coal preparation plants is usually caused by a few readily identifiable items of equipment that are much noisier than others, or by items located outside of buildings or near openings⁽⁷⁻¹⁾. For items located near openings, it is usually recommended that these openings be closed or provided with mufflers or barriers. Where building walls are of lightweight construction, heavier or secondary walls are suggested to reduce plant noise⁽⁷⁻¹⁵⁾.

right of termination may be based on any circumstance in the contract and is absolute; in some agreements, cancellation technically can be based only on price. Nonetheless, these contracts effectively bind the parties for only one year at a time.

Industrial contracts for metallurgical coal are equally short term. Even the industry giant U.S. Steel Corporation, which currently purchases 8 million tons of metallurgical coal annually from outside sources, relies primarily on short-term agreements. Over 80 percent of its "noncaptive" metallurgical coal is received under contracts of no more than 5 years' duration.

Suppliers of metallurgical coal seem to prefer short-term contracts as well. Recently, Avery Coal Company of Pennsylvania entered into a 5-year, 57-million dollar metallurgical coal contract. Industry-wide response was one of surprise since that contract was considered "long term" by usual standards. Most metallurgical coal suppliers prefer evergreen contracts while waiting for a possible upturn in the steel industry which might raise prices significantly.

Thus, most industrial coal agreements are short enough so that they would not serve as a contractual obstacle to PCC. As indicated, the situation is reversed in the utility sector where contracts are decidedly long term.

Revised or More Stringently Enforced SIP'S

Assume that a utility has entered into a long-term contract for unwashed coal. Subsequently, as a result of a revised or more stringently enforced state standard, the coal can no longer be burned in compliance with emission limits. Contract coal could be cleaned to meet the revised standards in some instances; in others it could not. In either event, however, the issue for consideration is to what extent the existing contractual arrangements might encourage or discourage PCC as an option for achieving compliance.

Relevant Contract Provisions

Although long-term coal supply contracts vary considerably, the clauses that deal with this particular contingency are relatively uniform. In some contracts they are labeled force majeure (act of God) and in others "compliance with antipollution laws". Notwithstanding the nomenclature, these provisions fall within one of three mutually exclusive categories:

- Early termination without penalty
- Early termination with penalty
- Take or pay.

It is important to note that virtually all coal-supply contracts contain one of these three types of provisions. Since the clauses are mutually exclusive, only one can and will be used in any given contract. Each represents a different way of dealing with the potential problem of changed emission standards and, accordingly, each spreads the risk of changed government regulations differently. The following discussion describes each type of clause and suggests under what circumstances it is most likely to be written into a coal-supply contract.

Early Termination Without Penalty. This type of provision, the most common of the three, gives a coal buyer the right to cancel a long-term supply contract without penalty if changed government regulations make it impossible for the user to meet new standards with contract coal. Contracts negotiated during the 1960's, and in some cases early 1970's, often included this in a general purpose force majeure clause. A typical example reads as follows.

If, because of force majeure, either party hereto is unable to carry out any of its obligations under this agreement either in whole or in part, and if such party promptly gives to the other party hereto notice of such force majeure, then the obligation of the party giving notice shall be suspended....

The term "force majeure" as used herein shall mean any causes beyond the control of the party affected thereby such as: acts of God, acts of the public enemy, insurrections, riots, strikes, labor disputes, labor or material shortages, fires, explosions, floods, breakdowns of or damage to plants, equipment or facilities, legislation by federal, state, provincial or local government authorities, orders or acts of

civil or military authority or other causes of a similar nature which wholly or partly prevent the parties or either of them from carrying out the terms of this agreement. (Emphasis added.)

As the parties to these contracts became more aware of the influence of government regulations, supply contracts began to address the problem more directly. Contracts signed in the early 1970's were more likely to include language like the following in an early termination without penalty clause.

In addition to grounds for termination which may be available to either party for breach of one or more provisions of this Agreement, termination may be had by Buyer as follows:

In the event that during the term of this Agreement restrictions are imposed by law or governmental agency which restrict the Buyer from burning the coal supplied under this Agreement, or, if for any reason use of the coal supplied under this Agreement results in violation of regulations in effect at the time, the Buyer shall have the right to terminate this Agreement by giving ninety (90) days written notice to the Seller and Buyer may terminate this Agreement effective upon expiration of the ninety (90) days.

Many agreements negotiated in the last several years require the purchaser to take all "reasonable" steps to comply with revised pollution control regulations by first attempting to use contract coal before terminating the contract. Still, it is generally specified that no steps are deemed reasonable if the total cost to the buyer under the contract would then exceed the cost of available competitive fuels. A typical clause found in recently negotiated contracts reads as follows.

The parties hereto recognize that, during the term of this Agreement, legislative or regulatory bodies or the courts having competent jurisdiction over the subject matter hereof may enact laws, regulations, or issue orders such as, but not limited to, those relating to air pollution, the effect of which will make it impossible or impractical for Buyer to utilize the coal subject hereto without substantially changing or altering its utilization equipment. Such laws, regulations or orders may pertain to, but would not necessarily be limited to, sulfur content of the coal. If any such laws, regulations or orders are imposed, Buyer shall immediately notify Seller thereof and to the extent it deems proper, proceed to exhaust the administrative remedies available to it to avoid the effect of such restriction. If such action does not avoid the effect of such restriction, Buyer shall promptly consider what steps can be taken in the handling and combustion of coal at Buyer's plant to avoid such restriction; and if such steps are available, which are feasible and will not result in unreasonable expense to Buyer, Buyer shall promptly take such steps, and this Agreement shall continue in full

force and effect. Such steps shall include the installation of equipment which is commercially available and which can be reasonably expected to avoid the effect of such restriction or which will result in compliance therewith. If no such steps are available, or if such steps are not feasible or will result in unreasonable expenses to Buyer, Buyer shall so advise Seller. Thereupon Buyer and Seller shall promptly consider what steps can be taken in the mining and preparation of coal at the mine to avoid such restriction, and if such steps are available at reasonable expense, such steps will be taken and the price of coal shall be increased to compensate Seller for any such additional reasonable expense incurred by it in taking such steps. No expense contemplated by this Section shall be deemed reasonable if it would result in a total cost to Buyer, in using Seller's coal, in excess of the total cost of using competitive fuels which are then reasonably available to Buyer and which can be utilized in conformity with all such restrictions. If Buyer is unable to comply with any such law, regulation or order in the manner provided in this Section, it shall have the right to cancel this Agreement without penalty.

Despite the semantic differences, the ultimate effect of these three clauses is basically the same. In each case, the utility may terminate its contract without penalty. Today, a utility can usually get this type of provision included in a coal-supply contract if that utility represents only a small percentage of the coal company's business at a given mine. Alternatively, if the utility is one of the mine's major customers, then it may have to pay a higher tonnage cost for the contract coal in order to get an early termination without penalty clause written into its long-term supply contract. Still, these clauses are widely used.

Early Termination With Penalty. This type of provision deals with the problem of revised SIP's in a manner less favorable to the utility. Generally, these clauses have been written into some of the coal contracts signed within the last two or three years. Under this arrangement, the utility can terminate its supply contract in the event of changed government regulations which prevent it from burning contract coal, but it is required to pay the coal company a penalty unless that coal is resold. Typically, these clauses are when a coal company opens a mine for one or two large utility customers only, when a mine is geographically isolated, when a particularly large initial capital investment is required, or when it is uncertain from the start that the utility company may subsequently be permitted to burn the mined coal as is. Clearly, the purpose of the penalty provisions is to shift some of the

risk for changed government regulations from the coal company to the utility company.

The mechanics for calculating the penalty, its amount, and the terms of payment are contract-specific. In some cases, the penalty is a lump sum amount based on a percentage of the coal company's capital investment. In others it is a per tonnage amount for the duration of the contract. Lump sum figures are usually calculated on the basis of very complex capital cost formulas while tonnage termination costs range from 20¢ a ton to several dollars. The total amounts vary enormously depending upon the nature of the mine and of the coal involved, the actual contract price, and the bargaining strength of the respective parties. The following represents a typical penalty clause.

[In the event that changed government regulations prevent Buyer from burning contract coal] . . . Buyer will have the right to terminate provided Buyer agrees to pay the Seller an annual termination charge for the remaining life of this Agreement. This termination charge shall be equal to ____¢ per ton of the coal which Buyer is obligated to purchase under section ____ hereof. During any period in which Buyer is obligated to pay a termination charge, Seller shall use its best efforts to sell the tonnage which Buyer is obligated to purchase hereunder to others.

After Seller has shipped all of the tonnage contracted from the Mine to others in any Contract Year, should the Seller sell any of the tonnage which Buyer is obligated to purchase hereunder during said Contract Year to others, in that event, the aforesaid termination charge will be either reduced or eliminated on the following basis:

- if the sales price per ton for such coal sold to others is less than the Adjusted Base Price hereunder, the termination charge shall be reduced to an amount equal to the difference between the sales price per ton to others and the Adjusted Base Price which would then have been in effect hereunder, not to exceed ____¢ per ton; or
- if the sales price per ton for such coal sold to others is greater than said Adjusted Base Price, the termination charge shall be eliminated.

In some cases the penalty continues in full force for the life of the contract, unless the coal is resold. In others, the penalty is reduced or even eliminated after a specified period of months or perhaps years. Again, these terms are carefully negotiated by the parties depending upon their needs at the time the contract is entered into.

Take or Pay. A final type of arrangement, least favorable to the utility company, requires that the utility pay for all coal specified in its contract, even if it can no longer burn the coal due to changed government regulations. Many older contracts negotiated in the 1960's, before air pollution control regulations proliferated, were of this variety. Force majeure clauses made no reference to legislative or administrative action and, consequently, the utility was provided no way in which to terminate its contract when the coal under order failed to meet new SO₂ emission standards.* Today, a few newer contracts specifically prohibit early termination in the event of changed pollution standards, but that is far less common than the early termination clauses just discussed.

It is virtually impossible to specify under what conditions each of the three types of clauses will appear. Aside from generalizations already discussed, the clause actually used will depend ultimately on the unique mix of circumstances in each contract setting.

Effect of Contract Provisions on the PCC Option

Regardless of the termination provision drafted, the parties typically prefer to work within the existing contractual framework rather than terminate the arrangement following a change in emission limits. If the clause used is an early termination without penalty provision, the utility company could simply walk away from its contract. There are several reasons why it is reluctant to do so.

- The utility may not wish to abandon a reliable supplier with whom a good working relationship has been established.
- It is usually costly to find a new source of supply on short notice.
- Frequently, the current supplier's employees are utility customers. Contract termination could produce layoffs and resentment toward the utility among neighboring miners.
- The suitability of contract coal following changed regulations might be unclear. Terminating the contract could lead to a protracted and expensive lawsuit.

* Of course, the utility could always break its contract and risk a lawsuit by the coal company. The ramifications of that alternative are discussed below.

- Many contracts signed in the 1960's (during the zenith of mine safety legislation and plans for nuclear power expansion) resulted in coal prices advantageous to utilities. The utilities are now reluctant to terminate these agreements.

When a termination with penalty provision is involved, there is even greater reluctance to terminate. In that case, neither party to the agreement wants the economic uncertainty (based on whether contract coal can be resold) which necessarily results from early termination.

Even in the case of take-or-pay clauses, many coal companies are reluctant to force customers to pay for unusable coal. Many of the "good business" reasons affecting utility reluctance to terminate apply with equal force on the supplier side. In addition, under some circumstances, a utility might in court assert "commercial impracticability" in the case of a take-or-pay contract and be permitted to break the contract with impunity. Accordingly, regardless of the type of clause involved, most parties, in the event of the scenario described as Case 1, would renegotiate existing contracts. In doing so they would seek the least costly method of compliance with the new SO₂ standards.

There are several ways in which a contract may be renegotiated such that the contract remains in force and the utility still complies with a tightened standard.*

- The utility may assign its coal contract to another utility and look for compliance coal elsewhere.
- The utility may, if it is large enough, use the contract coal at another one of its plants.
- The parties may agree to double the life of the existing contract such that the utility takes only half of its allotted shipment in each calendar year. It may then seek low sulfur coal elsewhere and blend that with contract coal in order to meet the new standard.
- The coal company may sell the contract coal elsewhere and supply the utility with compliance coal, perhaps at a higher price.

* It is assumed that the utility would obtain a variance until the appropriate option was implemented.

- The utility may retrofit a flue gas desulfurization (scrubber) system.
- The parties may agree to invest in a PCC plan so that contract coal can be washed to meet the new standard.
- The parties may seek a variance or compliance schedule from the state EPA such that contract coal may be burned until the end of the existing contract, or at least until an alternative compliance strategy can be developed.
- The parties may submit the entire issue to arbitration and agree to be bound by the decision of the arbitration board.

If the contract renegotiation alternative is selected, it is clear that the PCC option is but one of many. There is nothing in the relevant contract provisions which would serve as an obstacle to that alternative; there is nothing to promote it. The utility would make a decision based on economic considerations applicable to its particular situation.

A similar consequence follows in the less likely event that a contract is actually terminated. At that time a utility would ordinarily be free to seek a new source of compliance coal. Clearly, in that circumstance, the terminated contractual obligation has no effect on the utility's decision to either invest in a PCC facility or seek washed coal. Again, there are several options and the final decision is presumably based on economic grounds.

It is possible, however, that under certain circumstances, utilities which are renegotiating existing coal contracts are less likely to select the PCC option than ones that have terminated these obligations. This might occur in a take-or-pay situation when the coal company has the leverage to force customers to accept a renegotiated alternative which is less economically attractive than PCC. (For reasons discussed below, it is unlikely that the utility would break its contract in order to find a new supplier with cleaned coal.) It might also occur in an early termination situation when termination and purchasing of washed coal elsewhere would cost less than accepting contract coal and blending it. In such a case, continuation of the existing contract with a reliable supplier might outweigh a small immediate economic benefit to be gained from termination and PCC. Thus, the utility might stay within the existing contract and agree to forego the alleged least costly PCC option if the coal company refused to consider it.

In sum, long-term contractual obligations will have very little impact on widespread implementation of PCC in response to revised SIP's. Under certain limited circumstances, the contracts may serve as a minor obstacle to coal cleaning. Still, the nature of these contracts and the relationship of the parties is such that the PCC decision will be made primarily on economic grounds, and usually within the context of long-term coal contracts in effect.

Cost and/or Technology Changes Favorable to PCC

Scenario Case 2 assumes that, as a result of economic factors either in the marketplace or in the public sector, the PCC option has become the most economically attractive SO₂ control strategy for the utility. This section evaluates whether under this circumstance existing contractual arrangements serve as a constraint on the implementation of PCC.

Relevant Contract Provisions

Most contracts address this problem only tangentially in what are often called "economic hardship" provisions. Typically they read:

Any gross inequity that may result from unusual economic conditions not contemplated by the parties at the time of execution of this Agreement shall be corrected by mutual agreement, but nothing contained in this Section shall relieve any party from the continued performance of its obligations hereunder.

As a practical matter, this type of clause often has a very limited effect. Accordingly, some contracts include more elaborate provisions dealing with this contingency. For example:

Seller and Buyer acknowledge the possibility of either party's sustaining an actual economic hardship under this Agreement because of conditions which were unforeseeable in
At any time either party believes it has sustained an actual unforeseeable hardship under this Agreement and wishes to invoke the provisions of this Section to obtain relief, if any, it shall give notice in writing to the other party...stating the relief it considers reasonable...

Upon receipt of the notice set forth above, the party receiving such notice shall consider the documentary proof submitted and any other relevant matters, and if...it finds that the party sending such notice has sustained an actual unfavorable economic hardship due to the cause stated in such notice and is entitled to relief hereunder, the party receiving such notice shall... provide relief. The party receiving such notice shall not (act) arbitrarily...

Economic hardship arising from any of the following types of causes or conditions shall not be grounds for relief hereunder:

- (i) where the cause or condition results from a matter involving the internal operations of the party claiming that it has sustained an actual economic hardship;
- (ii) changes in the market for coal resulting from competitive factors; or
- (iii) availability or costs of alternative fuels.

Effect of Contract Provisions
on the PCC Option

It is highly unlikely that the contingencies envisioned in this case would be covered by these types of clauses. Traditionally, such provisions have not been applied to buyers with long-term contracts for materials which prevented them from adopting more economic technologies. Even if the clauses were applicable, however, they merely call for renegotiation of existing arrangements, an alternative which would probably occur in any event.

This scenario introduces another element into the decision-making equation. If washed coal became more economic for a utility than unwashed (but lower sulfur) contract coal, the utility might wish to break its contract altogether. (A related incentive may exist for a utility to break a take-or-pay contract in response to Scenario Case 1). In either case that response is unlikely. The cost of breaking long-term coal-supply contracts is high, both in terms of business relationships and dollars.

Breaking coal contracts - as opposed to terminating contracts pursuant to the agreement of both parties - usually involves an extended and extremely costly lawsuit. The losing party (generally the side that breached its agreement) must not only pay for out-of-pocket and consequential damages sustained by the other side, but also for its own attorney fees and court costs. Where large-scale contracts are involved, this will amount to millions of dollars. It is reasonably unlikely that coal cleaning would become so economically superior to other alternatives that a utility would break an existing contract in order to pursue the PCC option.

Consequently, if under Scenario Case 2 PCC became the most economically preferable option, it is probable that coal companies and utilities would in some cases renegotiate existing contracts to provide for its implementation. The utility might have to finance a large percentage of the undertaking. In the few cases where physical coal cleaning was not feasible from a supplier's perspective, existing long-term coal-supply contracts would serve as an obstacle to PCC since it is improbable that many utilities would break these contracts.

Regulations Limiting Sulfur Content of Coals Sold in Selected Regions

Although there is no direct precedent for this type of regulation, and it may create certain administrative and equity problems, it should not be ruled out as a possible policy alternative. As such, its impact on the PCC option, in the context of existing contractual arrangements is outlined below.

Relevant Contract Provisions

Although policies altering SO₂ emission levels trigger contract clauses such as force majeure and compliance with antipollution laws provisions, which ultimately affect utility responses, a policy directed at the sulfur level of coals sold would trigger a very different clause in these contracts. That policy would set in motion the price adjustment clauses which are meant to protect the supplier.

Price adjustment clauses are lengthy and detailed and have been written into virtually all coal-supply contracts for many years. In major contracts, these clauses are routinely ten to twenty pages long, sometimes more. Since coal agreements historically have been long term, it always has been necessary to specify carefully the ways in which the base contract price would rise over time to accurately reflect increased mining costs (whether caused by economic factors or government intervention).

Price adjustment provisions address a wide range of cost components. Some cost components are tied to recognized indices such as specific elements of the Wholesale Price Index; others are governed by formulas negotiated by the parties. A large coal contract signed in 1973 included separate price adjustment provisions for each of the following mining cost components:

- Materials and supplies
- Labor: salaries, welfare, and pension benefits
- Costs based upon values (ad valorem property taxes)
- Costs based upon extraction
- Other costs for the right to mine
- Other new, increased taxes
- Transfer taxes
- Quality adjustment (for coal not meeting contract specifications)
- Additional costs imposed by changes in the method of operation due to material shortages
- Additional costs imposed by legislation, regulation, or judicial action.

As suggested by the size and completeness of this list, coal companies and utilities have had long experience with these types of provisions. In most cases, the formulas have been adjusted so that they represent equitable arrangements, acceptable to both sides.

The price adjustment item relevant to the situation considered here is, of course, the final one on the above list. Although the specifics of these provisions vary, a typical clause referring to costs imposed by government regulation reads as follows:

The following will be included in calculation of escalation charges: All costs of complying with Federal, State, or Local laws, rules or regulations, whether due to existing laws, rules, or regulations or to changes in, additions to or difference in interpretation or enforcement by any governmental authority of existing laws, rules or regulations or due to enactment of new Federal, State, or local laws, rules or regulations, to the extent that such increases cause the total cost of complying with such laws, rule or regulations to exceed the amount included in the Base Price for this item. Costs covered by this paragraph include but are not limited to those of reclamation, prevention or reduction of water and air pollution, protection of hydrological balance, and compliance with mine safety laws and environmental quality acts, including bond premiums for bonds required to be posted thereunder.

Following that statement is a precise formula specifying the mechanics for calculating an increment to the base price.

Effect of Contract Provisions on the PCC Option

If coal companies were forced to physically clean certain coals in order to make them legally saleable, they would be responsible for investing in the PCC facility. Although a coal cleaning plant is not the usual expense measure

envisioned by these clauses, it is a capital investment that could be passed along directly to the utilities via the price adjustment mechanism. Furthermore, in most states, utilities can pass price adjustment clause increases directly to customers through their own fuel adjustment mechanisms without formal proceedings before their respective public utility commissions.

Thus, in the event of Scenario Case 3, existing contractual obligations would not serve as an obstacle to PCC. In fact, the contracts are set up in such a way that the PCC option could be readily incorporated.

Conclusions

When some of the situations in which PCC may emerge as a desirable SO₂ control option are specified, and then the relevant provisions of typical utility coal contracts are analyzed in that context, it appears that there are relatively few instances in which the terms of the contracts themselves would strongly deter investments in coal cleaning.

In the case of revisions or better enforcement of SIP standards, most parties would attempt to renegotiate their contract in order to avoid termination. In such event, PCC is one option of many and probably could be implemented by the parties if it was clearly the least costly alternative. The same outcome would result in the case of terminated contracts. In two limited circumstances, however, existing contractual obligations might bar its implementation:

- The coal contract contains a take-or-pay provision, the coal company uses that as leverage to refuse consideration of PCC, and the utility does not breach its agreement.
- The coal contract contains an early termination provision, the coal company refuses to consider PCC, and the utility values a continued relationship with a reliable supplier more than implementation of a slightly less expensive pollution control technology.

Neither combination of circumstances is likely to occur frequently.

In the event of cost and/or technology changes very favorable to PCC, contracts could be renegotiated to provide for PCC. In cases where the coal company was unable to supply cleaned coal, however, most utilities would probably not abrogate existing agreements, and the contract might then serve as an obstacle to adoption of PCC. Still, if PCC became increasingly widespread, it is unlikely that a substantial number of coal companies would refuse to consider it for existing contract customers.

In the case of implementation of regulations limiting the sulfur content of coals sold in selected regions, it is unlikely that existing contractual arrangements would discourage PCC. On the contrary, price adjustment clauses in these contracts are structured in such a manner that the PCC option might actually be encouraged. Regulations aimed at ensuring that only washed coal was sold in selected areas could make use of a preexisting and well planned contract provision to accomplish this goal. Also, the ease with which a coal cleaning investment could be passed along via price adjustment and subsequently fuel adjustment mechanisms may render this a relatively attractive option to the parties involved.

Still, the feasibility, effectiveness, and equity of this type of regulation are unclear. EPA should investigate the potential ramifications of such a policy in other contexts, particularly its likely economic and social impact on both coal companies and utilities. The equity of this type of regulatory mechanism also must be carefully studied as should its political acceptability to the affected parties.

Because a policy limiting the sulfur content of coals sold in certain regions represents a new type of SO₂ emission control strategy, EPA's authority to promulgate in this way, as well as the workability of such regulations, would have to be systematically analyzed. Finally, this policy could generate a variety of enforcement problems. These, too, would necessarily require scrutiny.

Under the existing SO₂ regulations, the provisions in long-term coal-supply contracts do nothing to promote PCC. In limited circumstances, they discourage that option. Regulation of the sulfur content of coals sold in certain areas could encourage PCC in the context of existing contractual obligations. If such a stratagem survives analysis in other contexts, it might be an appropriate regulatory mechanism, especially for reducing sulfur emissions from the older power plants subject to SIP limitations.

APPENDIX D

DATA ON COAL-BURNING FACILITIES

APPENDIX D

DATA ON COAL-BURNING FACILITIES

Industrial Facilities

Boilers

The Federal Energy Administration (now incorporated in the Department of Energy) distributed a questionnaire to industry in 1975 to obtain information on fuel use. Return of the questionnaire was mandatory on the part of industry; however, electric power plants were excluded. Information was required to be submitted on the capacity of all fuel-burning equipment. More detailed information was required on all Major Fuel-Burning Installations (MFBI) which were defined as "boilers, burners, and other combustors" with capacity in excess of 100 million Btu per hour.

A computer tape containing this data file was obtained by Battelle and was used to extract boiler population information.^(D-1)

The number of boilers with coal as the primary fuel is shown in Table D-1 by state and size range. The number of boilers decreases progressively in each size range from the smallest included in this characterization to the largest size range. The same information is given in Table D-2 for boilers for which coal was listed as the alternative fuel. In this case the number of boilers in the size range of 300-399 million Btu per hour is slightly less than the number in each of the next two larger size ranges.

The distribution of boilers by age and state is shown in Table D-3 for coal as the primary fuel, and in Table D-4 for coal as the alternative fuel. The data in Table D-3 show that 40 percent of the boilers were more than 30 years old in 1975 and 60 percent were more than 25 years old. A similar pattern is shown in Table D-4 for boilers with coal as the alternative fuel. A cross comparison between age and boiler size is shown in Tables D-5 and D-6.

Each of these existing coal-burning boilers is subject to SO₂ emission regulations under the State Implementation Plans (SIP's). These regulations

TABLE D-1. NUMBER OF BOILERS BY STATE AND SIZE RANGE (10^6 BTU/HR), COAL AS PRIMARY FUEL (a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA	13	11	6	--	2	--	32
ALASKA	27	--	--	--	--	--	27
ARIZONA	--	--	--	--	--	--	--
ARKANSAS	--	--	--	--	1	--	3
CALIFORNIA	1	1	--	--	--	--	16
COLORADO	12	4	--	--	--	--	--
CONNECTICUT	--	--	--	--	--	--	--
DELAWARE	4	7	--	--	--	--	11
DISTRICT OF COLUMBIA	--	--	--	--	--	--	--
FLORIDA	--	--	--	--	1	--	4
GEORGIA	1	2	--	--	--	--	--
HAWAII	--	--	--	--	--	--	--
IDaho	4	4	1	--	--	--	9
ILLINOIS	28	12	4	4	--	2	51
INDIANA	40	3	5	7	1	4	60
IOWA	10	1	2	--	--	--	13
KANSAS	--	--	--	--	--	--	--
KENTUCKY	17	11	--	--	--	--	28
LOUISIANA	1	--	--	--	--	--	1
MAINE	--	--	--	--	2	--	2
MARYLAND	--	--	--	--	--	--	--
MASSACHUSETTS	--	--	--	--	--	--	--
MICHIGAN	69	13	3	2	--	--	87
MINNESOTA	11	1	--	--	--	--	12
MISSISSIPPI	12	--	1	--	--	--	13
MISSOURI	--	--	--	--	--	--	--
MONTANA	--	3	--	--	--	--	3
NEBRASKA	--	--	--	--	--	--	3
NEVADA	2	--	1	--	--	--	3
NEW HAMPSHIRE	--	--	--	--	--	--	--
NEW JERSEY	5	--	--	--	--	--	5
NEW MEXICO	--	--	--	--	--	--	--
NEW YORK	18	12	--	3	1	--	34
NORTH CAROLINA	13	8	1	3	--	--	25
NORTH DAKOTA	--	1	--	--	--	--	1
OHIO	75	12	11	6	8	--	112
OKLAHOMA	--	--	--	--	--	--	--
OREGON	1	1	--	--	--	--	2
PENNSYLVANIA	47	19	5	9	3	1	84
RHODE ISLAND	--	--	--	--	--	--	--
SOUTH CAROLINA	15	10	9	--	--	--	34
SOUTH DAKOTA	4	1	--	--	--	--	5
TENNESSEE	40	10	3	--	5	--	58
TEXAS	--	3	--	--	--	3	6
UTAH	3	2	--	3	--	--	8
VERMONT	--	--	--	--	--	--	--
VIRGINIA	23	7	5	1	1	--	37
WASHINGTON	11	1	1	--	--	--	13
WEST VIRGINIA	22	21	4	3	7	--	57
WISCONSIN	29	2	5	--	--	--	35
WYOMING	3	1	2	1	1	--	8
TOTAL	560	185	69	42	33	10	899

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-2. NUMBER OF BOILERS BY STATE AND SIZE RANGE (10^6 BTU/HR), COAL AS ALTERNATE FUEL(a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA	--	--	--	--	--	--	--
ALASKA	--	--	--	--	--	--	--
ARIZONA	--	--	--	--	--	--	--
ARKANSAS	--	--	--	--	--	--	--
CALIFORNIA	--	--	--	--	--	--	--
COLORADO	--	1	--	--	--	--	1
CONNECTICUT	3	1	--	--	--	--	4
DELAWARE	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	1	--	--	--	--	1
FLORIDA	--	--	--	--	--	--	--
GEORGIA	--	4	--	--	2	--	6
HAWAII	--	--	--	--	--	--	--
IDAHO	--	--	--	--	--	--	--
ILLINOIS	10	1	--	--	--	--	11
INDIANA	2	2	--	--	1	--	5
IOWA	2	3	--	--	--	--	5
KANSAS	--	2	--	--	--	--	2
KENTUCKY	2	--	--	--	--	--	2
LOUISIANA	--	--	--	--	--	--	--
MAINE	2	3	--	--	--	--	5
MARYLAND	3	--	--	--	--	--	3
MASSACHUSETTS	3	--	--	--	--	--	3
MICHIGAN	4	2	2	1	7	--	16
MINNESOTA	4	1	--	--	--	--	5
MISSISSIPPI	--	--	--	--	--	--	--
MISSOURI	--	1	--	--	--	--	1
MONTANA	--	--	--	--	--	--	--
NEBRASKA	--	--	--	--	--	--	--
NEVADA	--	--	--	--	--	--	--
NEW HAMPSHIRE	--	--	--	--	--	--	--
NEW JERSEY	8	2	--	--	--	--	10
NEW MEXICO	--	--	--	--	--	--	--
NEW YORK	1	--	--	--	--	--	1
NORTH CAROLINA	14	1	2	--	1	1	19
NORTH DAKOTA	--	--	--	--	--	--	--
OHIO	12	4	4	2	1	--	23
OKLAHOMA	--	--	--	--	--	--	--
OREGON	--	--	--	--	--	--	--
PENNSYLVANIA	--	--	--	--	--	--	--
RHODE ISLAND	5	3	--	3	--	--	11
SOUTH CAROLINA	--	--	--	--	--	--	--
SOUTH DAKOTA	1	--	--	2	--	--	3
TENNESSEE	--	--	--	--	--	--	--
TEXAS	4	5	2	2	--	--	13
UTAH	--	--	--	--	1	--	4
VERMONT	--	--	--	--	--	--	--
VIRGINIA	14	1	1	2	--	--	18
WASHINGTON	3	--	--	--	--	--	3
WEST VIRGINIA	--	2	--	--	--	--	2
WISCONSIN	3	--	--	--	--	--	3
WYOMING	--	--	--	--	--	--	--
TOTAL	102	40	11	15	13	1	182

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-3. NUMBER OF BOILERS BY STATE AND YEARS OF AGE, COAL AS PRIMARY FUEL(a)

	0-5	6-10	11-15	16-20	21-25	25-30	30+	TOTAL
ALABAMA	--	--	--	--	3	3	14	32
ALASKA	--	--	8	--	15	12	--	27
ARIZONA	--	--	--	--	--	--	--	--
ARKANSAS	--	--	--	--	--	--	--	--
CALIFORNIA	1	--	--	--	--	1	--	3
COLORADO	--	--	--	1	2	3	10	16
CONNECTICUT	--	--	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	3	3	5	11
FLORIDA	--	--	--	--	--	--	--	--
GEORGIA	--	--	--	--	--	--	--	--
HAWAII	--	--	1	1	2	--	--	4
IDAH0	--	--	--	--	--	--	--	--
ILLINOIS	1	1	1	--	--	2	4	9
INDIANA	3	6	9	8	10	12	12	51
IOWA	--	1	2	7	12	9	14	60
KANSAS	--	--	--	3	--	--	7	13
KENTUCKY	2	--	--	--	--	--	--	--
LOUISIANA	--	1	3	3	6	2	11	28
MAINE	--	--	--	--	--	--	1	1
MARYLAND	--	--	--	--	--	--	--	--
MASSACHUSETTS	--	--	1	1	--	--	--	2
MICHIGAN	--	--	--	--	--	--	--	--
MINNESOTA	3	8	7	7	10	23	29	87
MISSISSIPPI	--	1	2	--	2	2	5	12
MISSOURI	--	--	--	--	--	--	--	--
MONTANA	--	--	1	1	2	1	4	13
NEBRASKA	--	--	--	--	--	--	--	--
NEVADA	--	--	1	2	--	--	2	3
NEW HAMPSHIRE	--	--	--	--	1	--	--	3
NEW JERSEY	--	--	--	--	--	--	--	--
NEW MEXICO	--	--	--	1	--	--	4	5
NEW YORK	--	--	--	--	--	--	--	--
NORTH CAROLINA	--	2	5	5	4	5	13	34
NORTH DAKOTA	2	2	2	6	--	4	9	25
OHIO	--	--	1	--	--	--	--	1
OKLAHOMA	2	5	13	11	19	18	44	112
OREGON	--	--	--	--	--	--	--	--
PENNSYLVANIA	1	--	1	--	--	--	--	2
RHODE ISLAND	2	5	3	7	7	15	45	84
SOUTH CAROLINA	--	--	--	--	--	--	--	--
SOUTH DAKOTA	2	2	3	--	4	19	--	34
TENNESSEE	--	--	--	1	1	--	--	5
TEXAS	--	5	9	1	7	4	31	58
UTAH	--	--	1	2	--	3	5	6
VERMONT	--	--	--	--	--	--	--	--
VIRGINIA	1	--	6	1	1	5	23	37
WASHINGTON	--	1	--	--	3	--	9	13
WEST VIRGINIA	--	1	5	2	1	--	4	57
WISCONSIN	--	--	6	5	8	9	7	35
WYOMING	4	1	--	--	--	3	--	8
TOTAL	24	42	99	79	127	165	363	899

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-4. NUMBER OF BOILERS BY STATE AND YEARS OF AGE, COAL AS ALTERNATE FUEL(a)

	0-5	6-10	11-15	16-20	21-25	26-30	30+	TOTAL
ALABAMA	--	--	--	--	--	--	--	--
ALASKA	--	--	--	--	--	--	--	--
ARIZONA	--	--	--	--	--	--	--	--
ARKANSAS	--	--	--	--	--	--	--	--
CALIFORNIA	--	--	--	--	--	--	--	--
COLORADO	--	--	--	--	--	--	--	--
CONNECTICUT	--	--	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	--	--	--	--
FLORIDA	--	1	--	--	--	--	3	4
GEORGIA	--	--	--	--	--	--	--	--
HAWAII	--	--	--	--	--	--	--	--
IDaho	--	--	3	--	3	--	--	1
ILLINOIS	--	--	--	--	--	--	2	8
INDIANA	--	1	--	--	--	--	--	--
IOWA	--	3	--	2	2	3	--	11
KANSAS	--	1	1	--	--	--	1	5
KENTUCKY	--	--	--	--	1	--	2	2
LOUISIANA	--	--	--	--	--	--	--	--
MAINE	--	--	--	--	--	--	--	--
MARYLAND	--	--	--	--	--	--	--	--
MASSACHUSETTS	--	--	--	--	--	--	--	--
MICHIGAN	--	--	--	--	1	4	--	5
MINNESOTA	1	--	--	2	3	--	--	3
MISSISSIPPI	--	--	3	--	--	--	1	3
MISSOURI	--	--	2	2	6	2	4	16
MONTANA	--	--	--	--	1	--	--	5
NEBRASKA	--	--	--	--	--	--	--	--
NEVADA	--	--	--	--	--	1	--	1
NEW HAMPSHIRE	--	--	--	--	--	--	--	--
NEW JERSEY	--	--	--	--	--	--	--	--
NEW MEXICO	--	--	--	--	--	--	--	--
NEW YORK	--	--	--	1	3	3	3	10
NORTH CAROLINA	--	--	--	--	--	--	--	--
NORTH DAKOTA	--	--	4	--	2	4	1	11
OHIO	--	--	--	--	--	--	9	19
OKLAHOMA	--	--	2	--	3	6	12	23
OREGON	--	--	--	--	--	--	--	--
PENNSYLVANIA	--	--	--	--	--	--	--	--
RHODE ISLAND	--	2	--	2	2	--	--	11
SOUTH CAROLINA	--	--	--	2	--	--	--	--
SOUTH DAKOTA	--	--	--	2	1	--	--	3
TENNESSEE	--	--	--	--	--	--	--	--
TEXAS	--	2	2	--	--	--	--	13
UTAH	--	--	--	--	--	3	6	13
VERMONT	--	--	--	--	--	--	--	--
VIRGINIA	--	1	2	--	2	--	3	4
WASHINGTON	--	--	--	1	1	1	10	18
WEST VIRGINIA	--	--	--	--	--	--	--	--
WISCONSIN	--	--	--	--	1	2	2	3
WYOMING	--	--	--	--	--	--	--	--
TOTAL	1	11	20	13	34	36	67	192

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-5. NUMBER OF BOILERS BY SIZE (10^6 BTU/HR) AND YEARS OF AGE, COAL AS PRIMARY FUEL(a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
0-5 YEARS	8	8	2	3	3	--	24
6-10 YEARS	16	13	4	5	3	1	42
11-15 YEARS	43	22	14	10	8	2	99
16-20 YEARS	49	17	7	1	4	1	79
21-25 YEARS	97	12	10	3	5	--	127
25-30 YEARS	95	37	19	4	4	6	165
30+ YEARS	252	76	13	16	6	--	363
TOTAL	560	185	69	42	33	10	899

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-6. NUMBER OF BOILERS BY SIZE (10^6 BTU/HR) AND YEARS OF AGE, COAL AS ALTERNATE FUEL(a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
0-5 YEARS	--	--	--	1	--	--	1
6-10 YEARS	2	4	--	4	1	--	11
11-15 YEARS	7	2	4	1	5	1	20
16-20 YEARS	9	1	--	2	1	--	13
21-25 YEARS	18	10	3	1	2	--	34
25-30 YEARS	29	4	3	--	--	--	36
30+ YEARS	37	19	1	6	4	--	67
TOTAL	102	40	11	15	13	1	182

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

vary from state to state, and frequently different emission limits are stipulated in the SIP's for different areas within a state. In order to identify the particular SIP that would apply to each boiler, a correlation was developed between ZIP codes and current SIP emission limits. To simplify the computer programming, not more than two SIP levels were used in each state. The lower SO₂ emissions limit was designated the "metropolitan" SIP and the higher limit the "Nonmetropolitan" SIP. The MFBI file^(D-1) was read against the ZIP/SIP correlation, and the capacity of all boilers under a given SIP in each state was aggregated. The results are presented in Table D-7, which gives the boiler capacity (10⁶ Btu/hr) in each size range for each SIP in each state for coal as the primary fuel. In a similar format the aggregate of coal used (10⁹ Btu) in 1974 is given in Table D-8. These data were used to estimate the quantities of coal that could be made available to each of these SIP categories by means of various cleaning processes. This application is described in Appendix B.

Nonboilers

The MFBI data, file^(D-1) described previously was used to develop profiles of the nonboiler industrial uses of coal. The number of nonboiler applications using coal as the primary fuel is given by state and size range in Table D-9, and similar information for coal as the alternative fuel is given in Table D-10. As was the case for boilers, the greatest numbers of facilities occur in the smaller size ranges.

A breakdown of the number of nonboiler applications using coal as the primary fuel by state and by Standard Industrial Classification (SIC) is given in Tables D-11 through D-13, which show that nonboiler use of coal occurs almost exclusively in SIC 32, Stone, Clay, and Glass, and in SIC 33, Primary Metals. These applications are mostly coal-fired kilns and furnaces. The lower total number of applications shown in Table D-13 as compared with Table D-9 results from the fact that some of the entries in the MFBI file did not include an SIC designation.

TABLE D-7. CAPACITY OF COMBUSTORS BY STATE AND SIZE RANGE (10^6 BTU/HR) BOILER, COAL AS PRIMARY FUEL (a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA, METRO (SIP=1.4)	1,920	1,672	--	--	1,144	--	4,736
ALABAMA, NON-METRO, (SIP=6.0)	450	830	1,975	--	--	--	3,255
ALASKA, (NO SIP)	3,960	--	--	--	--	--	3,960
ARIZONA, (SIP=1.0)	--	--	--	--	--	--	--
ARKANSAS, (SIP=5.0)	--	--	--	--	--	--	--
CALIFORNIA, METRO (SIP=0.4)	154	250	--	--	620	--	1,024
CALIFORNIA, NON-METRO, (SIP=6.67)	--	--	--	--	--	--	--
COLORADO, (NO SIP)	1,929	847	--	--	--	--	2,816
CONNECTICUT, (SIP=0.4)	--	--	--	--	--	--	--
DELAWARE, METRO (SIP=1.6)	--	--	--	--	--	--	--
DELAWARE, NON-METRO, (NO SIP)	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA, (SIP=1.6)	660	1,897	--	--	--	--	2,557
FLORIDA, METRO (SIP=1.5)	--	--	--	--	--	--	--
FLORIDA, NON-METRO, (SIP=6.17)	--	--	--	--	--	--	--
GEORGIA, (SIP=4.0)	100	420	--	--	585	--	1,095
HAWAII, (NO SIP)	--	--	--	--	--	--	--
IDAHO, (SIP=1.6)	491	1,010	300	--	--	--	1,801
ILLINOIS, METRO (SIP=1.4)	264	1,129	330	--	--	--	1,727
ILLINOIS, NON-METRO, (SIP=6.0)	3,791	2,154	999	1,750	--	2,445	11,134
INDIANA, METRO (SIP=1.2)	4,792	679	1,700	3,020	670	7,332	15,193
INDIANA, NON-METRO, (NO SIP)	657	--	--	--	--	--	657
IOWA, (SIP=6.2)	1,454	208	691	--	--	--	2,353
KANSAS, (SIP=3.0)	--	--	--	--	--	--	--
KENTUCKY, METRO (SIP=1.2)	2,200	2,800	--	--	--	--	5,000
KENTUCKY, NON-METRO, (SIP=5.0)	209	--	--	--	--	--	209
LOUISIANA, (SIP=5.5)	185	--	--	--	--	--	185
MAINE, METRO (SIP=2.0)	--	--	--	--	--	--	--
MAINE, NON-METRO, (SIP=4.0)	--	--	--	--	--	--	--
MARYLAND, METRO (SIP=1.6)	--	--	--	--	1,320	--	1,320
MARYLAND, NON-METRO, (SIP=3.5)	--	--	--	--	--	--	--
MASSACHUSETTS, METRO (SIP=1.1)	--	--	--	--	--	--	--
MASSACHUSETTS, NON-METRO, (SIP=2.4)	--	--	--	--	--	--	--
MICHIGAN, METRO (SIP=3.0)	5,921	2,099	744	--	--	--	8,764
MICHIGAN, NON-METRO, (SIP=2.4)	3,455	1,130	370	960	--	--	6,315
MINNESOTA, METRO (SIP=3.0)	240	--	--	--	--	--	240
MINNESOTA, NON-METRO, (SIP=6.0)	1,064	250	--	--	--	--	1,314
MISSISSIPPI, (SIP=4.4)	--	--	--	--	--	--	--
MISSOURI, METRO (SIP=2.8)	1,789	--	345	--	--	--	2,135
MISSOURI, NON-METRO, (SIP=5.0)	--	--	--	--	--	--	--
MONTANA, (SIP=2.0)	--	--	--	--	--	--	--
NEBRASKA, (SIP=5.5)	--	600	--	--	--	--	600
NEVADA, METRO (SIP=0.15)	--	--	--	--	--	--	--
NEVADA, NON-METRO, (SIP=0.2)	280	--	339	--	--	--	619
NEW HAMPSHIRE, (SIP=4.0)	--	--	--	--	--	--	--
NEW JERSEY, METRO (SIP=0.32)	430	--	--	--	--	--	430
NEW JERSEY, NON-METRO, (SIP=1.6)	157	--	--	--	--	--	157
NEW MEXICO, (NO SIP)	--	--	--	--	--	--	--

TABLE D-7. (Continued)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
NEW YORK, METRO (SIP=0.4)	--	--	--	--	--	--	--
NEW YORK, NON-METRO, (SIP=3.9)	2,546	2,864	--	1,439	--	--	7,499
N. CAROLINA, (SIP=2.8)	1,665	1,670	395	1,260	640	--	4,990
N. DAKOTA, (SIP=3.0)	--	291	--	--	--	--	291
OHIO, METRO (SIP=1.4)	8,343	2,460	1,336	1,698	2,256	--	16,093
OHIO, NON-METRO, (SIP=4.5)	1,385	486	2,358	887	3,200	--	8,316
OKLAHOMA, (SIP=2.0)	--	--	--	--	--	--	--
OREGON, METRO (SIP=1.5)	--	--	--	--	--	--	--
OREGON, NON-METRO, (SIP=2.75)	105	273	--	--	--	--	378
PENNSYLVANIA, METRO (SIP=0.4)	3,338	2,530	626	3,509	2,010	1,250	13,263
PENNSYLVANIA, NON-METRO, (SIP=3.0)	2,935	1,706	1,021	416	--	--	6,078
RHODE ISLAND, (SIP=1.1)	--	--	--	--	--	--	--
S. CAROLINA, METRO (SIP=2.3)	--	--	--	--	--	--	--
S. CAROLINA, NON-METRO, (SIP=3.5)	2,795	2,540	3,528	--	--	--	8,863
S. DAKOTA, (SIP=3.0)	558	298	--	--	--	--	846
TENNESSEE, METRO (SIP=1.2)	5,258	1,020	1,174	--	2,510	--	9,962
TENNESSEE, NON-METRO, (SIP=4.0)	1,065	1,696	--	--	--	--	2,761
TEXAS, (SIP=3.0)	--	636	--	--	--	3,459	4,095
UTAH, (SIP=1.5)	444	402	--	1,209	--	--	2,055
VERMONT, (SIP=1.5)	--	--	--	--	--	--	--
VIRGINIA, METRO (SIP=1.06)	143	--	--	--	--	--	143
VIRGINIA, NON-METRO, (SIP=2.54)	3,403	1,736	1,582	436	670	--	7,827
WASHINGTON, (SIP=2.75)	1,122	225	306	--	--	--	1,653
WEST VIRGINIA, (SIP=2.6)	3,046	4,658	1,278	1,342	4,135	--	14,459
WYOMING, (SIP=1.2)	3,548	595	1,685	--	--	--	5,818
WYOMING, (SIP=0.3)	474	283	716	480	720	--	2,673

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-8. PRIMARY FUEL USED (10^9 BTU'S) IN COMBUSTORS BY STATE
AND SIZE RANGE BOILER, COAL AS PRIMARY FUEL, 1974 (a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA, METRO (SIP=1.6)	12,000	8,528	--	--	--	--	20,528
ALABAMA, NON-METRO, (SIP=4.0)	1,128	4,444	13,352	--	7,774	--	18,964
ALASKA, (NO SIP)	10,584	--	--	--	--	--	10,584
ARIZONA, (SIP=1.0)	--	--	--	--	--	--	--
ARKANSAS, (SIP=5.0)	--	--	--	--	--	--	--
CALIFORNIA, METRO (SIP=0.8)	546	1,144	--	--	--	--	1,690
CALIFORNIA, NON-METRO, (SIP=4.67)	--	--	--	--	--	--	--
COLORADO, (NO SIP)	6,256	2,856	--	--	--	--	9,112
CONNECTICUT, (SIP=0.8)	--	--	--	--	--	--	--
DELAWARE, METRO (SIP=1.6)	--	--	--	--	--	--	--
DELAWARE, NON-METRO, (NO SIP)	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA, (SIP=1.6)	2,734	5,404	--	--	--	--	8,138
FLORIDA, METRO (SIP=1.5)	--	--	--	--	--	--	--
FLORIDA, NON-METRO, (SIP=6.17)	--	--	--	--	--	--	--
GEORGIA, (SIP=4.0)	234	1,740	--	--	3,456	--	5,430
HAWAII, (NO SIP)	--	--	--	--	--	--	--
IDAHO, (SIP=1.6)	720	1,724	1,300	--	--	--	3,744
ILLINOIS, METRO (SIP=1.8)	1,536	4,442	--	--	--	--	7,448
ILLINOIS, NON-METRO, (SIP=6.0)	10,790	11,030	4,466	11,812	--	4,296	42,304
INDIANA, METRO (SIP=1.2)	18,366	1,224	8,450	16,618	3,354	51,546	99,758
INDIANA, NON-METRO, (NO SIP)	3,982	--	--	--	--	--	3,982
IOWA, (SIP=6.0)	5,592	648	4,620	--	--	--	10,860
KANSAS, (SIP=8.0)	--	--	--	--	--	--	--
KENTUCKY, METRO (SIP=1.2)	5,704	12,840	--	--	--	--	18,544
KENTUCKY, NON-METRO, (SIP=5.0)	--	--	--	--	--	--	--
LOUISIANA, (SIP=5.5)	240	--	--	--	--	--	240
MAINE, METRO (SIP=2.0)	--	--	--	--	--	--	--
MAINE, NON-METRO, (SIP=6.0)	--	--	--	--	--	--	--
MARYLAND, METRO (SIP=1.6)	--	--	--	--	--	--	--
MARYLAND, NON-METRO, (SIP=3.5)	--	--	--	--	7,560	--	7,560
MASSACHUSETTS, METRO (SIP=1.1)	--	--	--	--	--	--	--
MASSACHUSETTS, NON-METRO, (SIP=2.4)	--	--	--	--	--	--	--
MICHIGAN, METRO (SIP=3.0)	16,922	9,560	3,190	--	--	--	29,722
MICHIGAN, NON-METRO, (SIP=2.4)	13,530	2,338	3,068	2,532	--	--	21,528
MINNESOTA, METRO (SIP=3.0)	260	--	--	--	--	--	260
MINNESOTA, NON-METRO, (SIP=6.0)	3,978	1,176	--	--	--	--	5,154
MISSISSIPPI, (SIP=6.4)	--	--	--	--	--	--	--
MISSOURI, METRO (SIP=3.3)	4,864	--	1,144	--	--	--	6,012
MISSOURI, NON-METRO, (SIP=5.0)	--	--	--	--	--	--	--
MONTANA, (SIP=2.0)	--	--	--	--	--	--	--
NEBRASKA, (SIP=2.6)	--	2,062	--	--	--	--	2,062
NEVADA, METRO (SIP=3.15)	--	--	--	--	--	--	--
NEVADA, NON-METRO, (SIP=0.2)	390	--	--	--	--	--	390
NEW HAMPSHIRE, (SIP=6.0)	--	--	--	--	--	--	--
NEW JERSEY, METRO (SIP=0.32)	--	--	--	--	--	--	--
NEW JERSEY, NON-METRO, (SIP=1.4)	56	--	--	--	--	--	56
NEW MEXICO, (NO SIP)	--	--	--	--	--	--	--

TABLE D-8. (Continued)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
NEW YORK, METRO (SIP=0.4)	--	--	--	--	--	--	--
NEW YORK, NON-METRO, (SIP=3.8)	8,176	17,114	--	6,994	--	--	35,144
N. CAROLINA, (SIP=2.3)	4,290	5,546	1,560	8,190	2,860	--	19,536
N. DAKOTA, (SIP=3.0)	--	1,512	--	--	--	--	1,512
OHIO, METRO (SIP=1.4)	37,564	5,244	8,536	9,526	12,076	--	72,946
OHIO, NON-METRO, (SIP=4.5)	4,082	1,404	8,582	5,280	17,072	--	36,420
OKLAHOMA, (SIP=2.0)	--	--	--	--	--	--	--
OKLAHOMA, METRO (SIP=1.5)	--	--	--	--	--	--	--
OREGON, NON-METRO, (SIP=2.75)	260	800	--	--	--	--	1,060
PENNSYLVANIA, METRO (SIP=0.8)	21,860	3,904	--	24,934	13,852	1,980	66,530
PENNSYLVANIA, NON-METRO, (SIP=3.0)	11,138	7,978	4,980	1,606	--	--	25,702
RHODE ISLAND, (SIP=1.1)	--	--	--	--	--	--	--
S. CAROLINA, METRO (SIP=2.3)	--	--	--	--	--	--	--
S. CAROLINA, NON-METRO, (SIP=3.5)	8,768	9,750	18,760	--	--	--	37,288
S. DAKOTA, (SIP=3.0)	2,560	1,920	--	--	--	--	4,480
TENNESSEE, METRO (SIP=1.2)	20,848	2,556	10,104	--	21,216	--	54,724
TENNESSEE, NON-METRO, (SIP=4.0)	5,672	5,272	--	--	--	--	10,744
TEXAS, (SIP=3.0)	--	4,320	--	--	--	20,400	33,720
UTAH, (SIP=1.5)	432	2,704	--	8,346	--	--	11,482
VERMONT, (SIP=1.6)	--	--	--	--	--	--	--
VIRGINIA, METRO (SIP=1.06)	416	--	--	--	--	--	416
VIRGINIA, NON-METRO, (SIP=2.64)	15,120	8,480	11,432	1,920	4,320	--	41,272
WASHINGTON, (SIP=2.76)	2,136	384	528	--	--	--	3,048
WEST VIRGINIA, (SIP=2.6)	19,252	22,800	7,480	5,982	21,432	--	76,946
WISCONSIN, (SIP=1.2)	11,028	4,128	10,130	--	--	--	25,286
WYOMING, (SIP=0.3)	3,696	3,280	--	2,560	--	--	9,536

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-9. NON-BOILER USES OF COAL BY STATE AND SIZE RANGE (10^6 BTU/HR),
COAL AS PRIMARY FUEL (a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA	10	1	1	--	--	--	12
ALASKA	--	--	--	--	--	--	--
ARIZONA	1	--	--	--	--	--	1
ARKANSAS	--	--	--	--	--	--	--
CALIFORNIA	--	--	--	--	--	--	--
COLORADO	6	3	--	1	4	--	14
CONNECTICUT	--	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	--	--	--
FLORIDA	--	--	--	--	--	--	--
GEORGIA	1	1	--	--	--	--	2
HAWAII	--	--	--	--	--	--	--
IDAHO	5	--	--	--	--	--	5
ILLINOIS	6	1	2	--	1	--	10
INDIANA	26	8	4	5	2	3	48
IOWA	5	--	1	--	--	--	6
KANSAS	--	--	--	--	--	--	--
KENTUCKY	3	1	--	--	--	--	4
LOUISIANA	--	--	--	--	--	--	--
MAINE	--	--	--	--	--	--	--
MARYLAND	2	--	1	--	--	1	4
MASSACHUSETTS	--	--	--	--	--	--	--
MICHIGAN	4	4	--	3	2	2	15
MINNESOTA	--	--	--	--	--	--	--
MISSISSIPPI	--	--	1	--	--	--	1
MISSOURI	14	1	--	--	2	--	17
MONTANA	--	--	--	--	--	--	--
NEBRASKA	--	--	--	--	--	--	--
NEVADA	--	1	--	--	--	--	1
NEW HAMPSHIRE	--	--	--	--	--	--	--
NEW JERSEY	--	--	--	--	--	--	--
NEW MEXICO	--	--	--	--	--	--	--
NEW YORK	4	--	1	--	1	--	6
NORTH CAROLINA	--	2	--	--	--	--	2
NORTH DAKOTA	--	--	--	--	--	--	--
OHIO	21	11	3	--	--	2	37
OKLAHOMA	--	--	--	--	--	--	--
OREGON	3	--	--	--	--	--	3
PENNSYLVANIA	47	14	2	1	1	6	71
RHODE ISLAND	--	--	--	--	--	--	--
SOUTH CAROLINA	--	--	--	--	--	--	--
SOUTH DAKOTA	--	--	--	--	--	--	--
TENNESSEE	4	2	--	--	--	--	6
TEXAS	2	--	--	--	--	--	2
UTAH	15	--	--	--	--	--	15
VERMONT	--	--	--	--	--	--	--
VIRGINIA	3	1	--	--	--	--	4

TABLE D-9. (Continued)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
WASHINGTON	--	--	--	--	--	--	--
WEST VIRGINIA	3	2	2	--	--	--	7
WISCONSIN	--	--	--	--	--	--	--
WYOMING	1	2	--	--	--	--	3
TOTAL	166	55	16	10	13	14	296

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-10. NON-BOILER USES OF COAL BY STATE AND SIZE RANGE (10^6 BTU/HR),
COAL AS ALTERNATE FUEL (a)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
ALABAMA							10
ALASKA	4	5	1				--
ARIZONA	--	--	--				--
ARKANSAS	3	--	--				3
CALIFORNIA	--	--	--				--
COLORADO	6	--	3				9
CONNECTICUT	2	2	--				4
DELAWARE	--	--	--				--
DISTRICT OF COLUMBIA	--	--	--				--
FLORIDA	--	--	--				--
GEORGIA	2	--	1				3
HAWAII	--	--	--				--
IDAH0	1	--	--				1
ILLINOIS	--	--	--				--
INDIANA	1	--	--		4		5
IOWA	4	--	--		--		4
KANSAS	7	1	--		--		8
KENTUCKY	--	--	--		--		--
LOUISIANA	--	--	--		--		--
MAINE	--	--	--		--		--
MARYLAND	--	--	--		--		--
MASSACHUSETTS	--	--	--		--		--
MICHIGAN	1	--	--		--		1
MINNESOTA	--	--	--		--		--
MISSISSIPPI	--	--	--		--		--
MISSOURI	2	--	--		--		2
MONTANA	--	--	--		--		--
NEBRASKA	5	1	--		--		6
NEVADA	1	--	--		--		1
NEW HAMPSHIRE	--	--	--		--		--
NEW JERSEY	--	--	--		--		--
NEW MEXICO	--	--	--		--		--
NEW YORK	--	--	1		1		2
NORTH CAROLINA	--	--	1		--		1
NORTH DAKOTA	--	--	--		--		--
OHIO	3	1	--		--		4
OKLAHOMA	--	--	--		--		--
OREGON	1	--	--		--		1
PENNSYLVANIA	22	7	--		--		29
RHODE ISLAND	--	--	--		--		--
SOUTH CAROLINA	--	--	--		--		--
SOUTH DAKOTA	--	--	--		--		--
TENNESSEE	7	--	--		--		7
TEXAS	--	2	--		--		2
UTAH	2	--	--		--		2
VERMONT	--	--	--		--		--
VIRGINIA	--	--	--		--		--

TABLE D-10. (Continued)

	100-199	200-299	300-399	400-499	500-999	1000+	TOTAL
WASHINGTON	--	--	--	--	--	--	--
WEST VIRGINIA	--	--	--	--	--	--	--
WISCONSIN	--	--	--	--	--	--	--
WYOMING	--	--	--	--	--	--	--
TOTAL	74	19	7	--	5	--	105

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-11. NON-BOILER USES OF COAL BY STATE AND TWO-DIGIT SIC CODE
(19-26), COAL AS PRIMARY FUEL (a)

	19	20	21	22	23	24	25	26
ALABAMA	--	--	--	--	--	--	--	--
ALASKA	--	--	--	--	--	--	--	--
ARIZONA	--	--	--	--	--	--	--	--
ARKANSAS	--	--	--	--	--	--	--	--
CALIFORNIA	--	--	--	--	--	--	--	--
COLORADO	--	--	--	--	--	--	--	--
CONNECTICUT	--	--	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	--	--	--	--
FLORIDA	--	--	--	--	--	--	--	--
GEORGIA	--	--	--	--	--	--	--	--
HAWAII	--	--	--	--	--	--	--	--
IDAHO	--	5	--	--	--	--	--	--
ILLINOIS	--	--	--	--	--	--	--	--
INDIANA	--	--	--	--	--	--	--	--
IOWA	--	--	--	--	--	--	--	--
KANSAS	--	--	--	--	--	--	--	--
KENTUCKY	--	--	--	--	--	--	--	--
LOUISIANA	--	--	--	--	--	--	--	--
MAINE	--	--	--	--	--	--	--	--
MARYLAND	--	--	--	--	--	--	--	--
MASSACHUSETTS	--	--	--	--	--	--	--	--
MICHIGAN	--	--	--	--	--	--	--	--
MINNESOTA	--	--	--	--	--	--	--	--
MISSISSIPPI	--	--	--	--	--	--	--	--
MISSOURI	--	--	--	--	--	--	--	--
MONTANA	--	--	--	--	--	--	--	--
NEBRASKA	--	--	--	--	--	--	--	--
NEVADA	--	--	--	--	--	--	--	--
NEW HAMPSHIRE	--	--	--	--	--	--	--	--
NEW JERSEY	--	--	--	--	--	--	--	--
NEW MEXICO	--	--	--	--	--	--	--	--
NEW YORK	--	--	--	--	--	--	--	--
NORTH CAROLINA	--	--	--	--	--	--	--	--
NORTH DAKOTA	--	--	--	--	--	--	--	--
OHIO	--	--	--	--	--	--	--	--
OKLAHOMA	--	--	--	--	--	--	--	--
OREGON	--	3	--	--	--	--	--	--
PENNSYLVANIA	--	--	--	--	--	--	--	--
RHODE ISLAND	--	--	--	--	--	--	--	--
SOUTH CAROLINA	--	--	--	--	--	--	--	--
SOUTH DAKOTA	--	--	--	--	--	--	--	--
TENNESSEE	--	--	--	--	--	--	--	--
TEXAS	--	--	--	--	--	--	--	--
UTAH	--	--	--	--	--	--	--	--
VERMONT	--	--	--	--	--	--	--	--
VIRGINIA	--	--	--	--	--	--	--	--

TABLE D-11. (Continued)

	19	20	21	22	23	24	25	26
WASHINGTON	--	--	--	--	--	--	--	--
WEST VIRGINIA	--	--	--	--	--	--	--	--
WISCONSIN	--	--	--	--	--	--	--	--
WYOMING	--	--	--	--	--	--	--	--
TOTAL	--	8	--	--	--	--	--	--

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-12. NON-BOILER USES OF COAL BY STATE AND TWO-DIGIT SIC CODE
(27-34), COAL AS PRIMARY FUEL (a)

	27	28	29	30	31	32	33	34
ALABAMA	--	--	--	--	--	--	12	--
ALASKA	--	--	--	--	--	--	--	--
ARIZONA	--	--	--	--	--	1	--	--
ARKANSAS	--	--	--	--	--	--	--	--
CALIF CRNIA	--	--	--	--	--	--	--	--
COLORADO	--	--	--	--	--	1	13	--
CONNECTICUT	--	--	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	--	--	--	--
FLORIDA	--	--	--	--	--	--	--	--
GEORGIA	--	--	--	--	--	2	--	--
HAWAII	--	--	--	--	--	--	--	--
IDAHO	--	--	--	--	--	--	--	--
ILLINOIS	--	--	--	--	--	7	1	--
INDIANA	--	--	--	--	--	14	34	--
IOWA	--	--	--	--	--	3	--	--
KANSAS	--	--	--	--	--	--	--	--
KENTUCKY	--	--	--	--	--	3	--	--
LOUISIANA	--	--	--	--	--	--	--	--
MAINE	--	--	--	--	--	--	--	--
MARYLAND	--	--	--	--	--	3	1	--
MASSACHUSETTS	--	--	--	--	--	--	--	--
MICHIGAN	--	--	--	--	--	8	2	--
MINNESOTA	--	--	--	--	--	--	--	--
MISSISSIPPI	--	--	--	--	--	1	--	--
MISSOURI	--	--	--	--	--	17	--	--
MONTANA	--	--	--	--	--	--	--	--
NEBRASKA	--	--	--	--	--	--	--	--
NEVADA	--	--	--	--	--	--	1	--
NEW HAMPSHIRE	--	--	--	--	--	--	--	--
NEW JERSEY	--	--	--	--	--	--	--	--
NEW MEXICO	--	--	--	--	--	--	--	--
NEW YORK	--	--	--	--	--	6	--	--
NORTH CAROLINA	--	--	--	--	--	2	--	--
NORTH DAKOTA	--	--	--	--	--	--	--	--
OHIO	--	1	--	--	--	22	14	--
OKLAHOMA	--	--	--	--	--	--	--	--
OREGON	--	--	--	--	--	--	--	--
PENNSYLVANIA	--	--	--	--	--	31	39	--
RHODE ISLAND	--	--	--	--	--	--	--	--
SOUTH CAROLINA	--	--	--	--	--	--	--	--
SOUTH DAKOTA	--	--	--	--	--	--	--	--
TENNESSEE	--	--	--	--	--	4	--	--
TEXAS	--	--	--	--	--	1	--	--
UTAH	--	--	--	--	--	1	13	--
VERMONT	--	--	--	--	--	--	--	--
VIRGINIA	--	--	--	--	--	3	1	--

TABLE D-12. (Continued)

	27	28	29	30	31	32	33	34
WASHINGTON	--	--	--	--	--	--	--	--
WEST VIRGINIA	--	--	--	--	--	3	--	--
WISCONSIN	--	--	--	--	--	--	--	--
WYOMING	--	2	--	--	--	--	--	--
TOTAL	--	3	--	--	--	133	131	--

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

TABLE D-13. NON-BOILER USES OF COAL BY STATE AND TWO-DIGIT SIC CODE
(35-39), COAL AS PRIMARY FUEL (a)

	35	36	37	38	39	TOTAL*
ALABAMA	--	--	--	--	--	12
ALASKA	--	--	--	--	--	--
ARIZONA	--	--	--	--	--	1
ARKANSAS	--	--	--	--	--	--
CALIFORNIA	--	--	--	--	--	--
COLORADO	--	--	--	--	--	14
CONNECTICUT	--	--	--	--	--	--
DELAWARE	--	--	--	--	--	--
DISTRICT OF COLUMBIA	--	--	--	--	--	--
FLORIDA	--	--	--	--	--	--
GEORGIA	--	--	--	--	--	2
HAWAII	--	--	--	--	--	--
IDAHO	--	--	--	--	--	5
ILLINOIS	--	--	--	--	--	6
INDIANA	--	--	--	--	--	48
IOWA	--	--	--	--	--	3
KANSAS	--	--	--	--	--	--
KENTUCKY	--	--	--	--	--	3
LOUISIANA	--	--	--	--	--	--
MAINE	--	--	--	--	--	--
MARYLAND	--	--	--	--	--	4
MASSACHUSETTS	--	--	--	--	--	--
MICHIGAN	--	--	--	--	--	10
MINNESOTA	--	--	--	--	--	--
MISSISSIPPI	--	--	--	--	--	1
MISSOURI	--	--	--	--	--	17
MONTANA	--	--	--	--	--	--
NEBRASKA	--	--	--	--	--	--
NEVADA	--	--	--	--	--	1
NEW HAMPSHIRE	--	--	--	--	--	--
NEW JERSEY	--	--	--	--	--	--
NEW MEXICO	--	--	--	--	--	--
NEW YORK	--	--	--	--	--	6
NORTH CAROLINA	--	--	--	--	--	2
NORTH DAKOTA	--	--	--	--	--	--
OHIO	--	--	--	--	--	37
OKLAHOMA	--	--	--	--	--	--
OREGON	--	--	--	--	--	3
PENNSYLVANIA	--	--	--	--	--	70
RHODE ISLAND	--	--	--	--	--	--
SOUTH CAROLINA	--	--	--	--	--	--
SOUTH DAKOTA	--	--	--	--	--	--
TENNESSEE	--	--	--	--	--	4
TEXAS	--	--	--	--	--	1
UTAH	--	--	--	--	--	14
VERMONT	--	--	--	--	--	--
VIRGINIA	--	--	--	--	--	4

TABLE D-13. (Continued)

	35	36	37	38	39	TOTAL*
WASHINGTON	--	--	--	--	--	--
WEST VIRGINIA	--	--	--	--	--	3
WISCONSIN	--	--	--	--	--	--
WYOMING	--	--	--	--	--	2
TOTAL	--	--	--	--	--	275

* Total includes Tables D-11, D-12, and D-13.

(a) Derived from 1974 data compiled in 1975 in Reference D-1.

Electric Utility Facilities

Data on coal-fired steam-electric power plants are reported by the National Coal Association ^(D-2). This appendix includes a summary of this information.

The number of power plants broken down by state and size range is shown in Table D-14. This sector differs from the industrial sector in that the largest numbers of boilers are not in the smaller sizes, but rather, the utility boiler distribution shows the greatest number in the range of 100 to 499 MW. Table D-15 gives the same type of information for utility boilers that use coal as an alternative fuel.

Reference D-2 lists steam electric power plants that are projected to come on stream through 1985. For the entire U.S. the following totals are given:

<u>Year</u>	<u>Number of Units</u>	<u>Capacity, MW</u>
1979	31	13,062
1980	34	16,688
1981	29	14,986
1982	27	13,039
1983	23	12,775
1984	25	13,536
1985	28	15,518
U.S. Total of Projected Additions	197	99,604

Reference for Appendix D

- (D-1) "Major Fuel Burning Installation (MFBI) Coal Conversion Report"
(a computer tape based on responses--in 1975--to Questionnaire designated FEAC-602-5-0, Federal Energy Administration (now Department of Energy), Washington, D.C.
- (D-2) Steam Electric Power Plant Factors - 1976, National Coal Association, 1130 Seventeenth Street, N.W., Washington, D.C. 20036.

TABLE D-14. NUMBER OF COAL-FIRED POWER PLANTS BY STATE AND SIZE RANGE,
COAL AS PRIMARY FUEL (a)

State	Megawatts					Total Number
	< 25	25-99	100-499	500-999	1000-2000	
Alabama		1	1	1	4	8
Arizona	2		1			2
Colorado	1	3	4	1	1	10
Connecticut						1
Delaware						1
Florida	1	1	1	1	2	5
Georgia	9	2	1	1	2	15
Illinois	3	5	9	7	6	30
Indiana	2	9	8	9	3	31
Iowa		3	7	1		11
Kansas		3	2			5
Kentucky			7	4	1	12
Maryland			1	2	3	6
Michigan	5	9	7	5	2	28
Minnesota	7	5	5	2	1	20
Mississippi	3	2	5	5	1	16
Missouri		1	2	1		4
Montana		2	5	5		12
Nebraska		1	2	1		4
Nevada			2	1		3
New Hampshire			1		1	2
New Jersey			1			1
New Mexico	1		1	1		3
New York		3	1			4
North Carolina	1		5	2	1	9
North Dakota	5	1	6	3	3	18
Ohio	4	7	4	6		21
Pennsylvania	2	4	11	6	7	30
South Carolina		4	12	4	7	27
South Dakota	3	2	8	1		14
Tennessee			1			1
Texas			1	3	3	7
Utah	2	1			1	4
Virginia	1	1	3	2		7
Washington			3			3
West Virginia				2		2
Wisconsin	2	5	5	1		13
Wyoming	1	2	9	1	1	14
Totals	55	68	136	67	56	395

(a) Derived from data from 1976 in Reference D-2.

TABLE D-15. NUMBER OF COAL-FIRED POWER PLANTS BY STATE AND SIZE RANGE,
COAL AS AN ALTERNATE FUEL (a)

State	Megawatts					Total Number
	< 25	25-99	100-499	500-999	1000-2000	
Alabama		1	1			2
Colorado			1			1
Delaware			1			1
District of Columbia				1		1
Georgia			1	1		2
Iowa	6	4	2			12
Kansas			1	1		2
Maryland					2	2
Massachusetts			1	1	1	3
Michigan		1		1		2
Minnesota	3	3	1			7
Mississippi	1					1
Missouri		2	2			4
Nebraska	1	2				3
New Jersey		1		1	1	3
South Dakota	1					1
Virginia					1	1
Wisconsin		1	1			2
Totals	12	16	12	6	5	51

(a) Derived from data from 1976 in Reference D-2.

APPENDIX E

POTENTIAL COMPUTATION OF SUPPLIES OF CLEAN COAL

APPENDIX E

POTENTIAL COMPUTATION OF SUPPLIES OF CLEAN COAL

The various analyses conducted by use of the Reserve Processing Assessment Model (RPAM) as described earlier provide detailed information on the quantities of coal in the reserve which could be cleaned sufficiently to meet various SO₂ emission limits. This information still does not answer the basic question, i.e., how useful is coal cleaning as an SO₂ emission control technique? The additional step needed, and the objective of this portion of the study, is to compare the quantities of compliance coal which could be produced by coal cleaning with the actual coal requirements of existing facilities operating under actual SO₂ emission limits. The results will indicate whether coal cleaning can reasonably provide the quality of coal required by SO₂ emission regulations now in force.

Approach

The analysis consists of the following steps.

- (1) Determine the coal demand of existing industrial and electric utility facilities.
- (2) Determine the SIP requirements for each facility.
- (3) Aggregate the demand of all the facilities in each state operating under specified SIP limits.
- (4) Compare the demands for coal of the required quality for each SIP with the quantities which could be made available by coal cleaning.

Six regions plus the entire U.S. are analyzed.

Industrial Coal Demand

The major source of data used to characterize industrial coal demand was the survey^{(E-1)*} conducted and reported by the Federal Energy Administration (now in DOE). Submission of reports by each major fuel burning installation was mandatory under P.L. 39-275. Data are for 1974. The survey required listing of the total capacity at each installation, but an itemized breakdown of information was required only for combustors of 100×10^6 Btu/hr fuel input or greater. Thus, it was necessary to synthesize the regional distributions of small combustors, defined as those with less than 100×10^6 Btu/hr input fuel capacity, because the total capacities of small combustors constitute approximately 40 percent of the total industrial fuel-burning capacity according to the MFBI survey results.

The procedure for this synthesis consisted of applying data from an EPA boiler survey on capacity distribution^(E-2) to estimate the allocation among coal, residual oil, distillate oil, gas, and other fuels for "small" boilers. The MFBI total of "small" and "large" boilers and "large" nonboilers was subtracted from the entire capacity in each region, thus determining the total of "small" nonboilers. There are no data on capacity distributions among fuels for "small" nonboilers. These capacities were distributed assuming that the ratios of "small coal nonboiler capacity" to "small gas nonboiler capacity" to "small residual nonboiler capacity", etc., were the same as similar ratios for large boilers. Thus, it was possible to determine "small" nonboiler capacities by difference.

The resulting listing, contained on a computer tape, identified each coal-burning facility by combustor type, capacity, and geographical location.

Utility Coal Demand

The source of data for utility coal demand was EPA's Energy Data System (EDS)^(E-3). This computer file lists the location and capacity of coal-fired utility boilers as of 1977.

* References for Appendix E are listed on page 318.

Assignment of SIP Levels

The EDS file on utility boilers includes information on the SO₂ emission regulation applicable to each boiler. This information was used to aggregate capacity in each state, region, and SIP level.

The MFBI file of industrial facilities does not contain any information on SO₂ emission limits applicable to each facility. The file does contain the ZIP code for each plant. In order to identify the appropriate SIP, a separate matrix was constructed relating ZIP code and SIP level. This was simplified by using at most two SIP standards (basically metropolitan and nonmetropolitan) in any one state. It was possible to assign the appropriate SIP regulation to each facility by means of this ZIP/SIP matrix.

Aggregation of Capacity

The data files described above were used to compute the total capacity in each state which operates under each SIP. The results of this aggregation are given in Table E-1 for industrial combustors and in Table E-2 for utility boilers. One or two entries are included in Table E-1 for each state. For double state entries, M designates the metropolitan classification and N designates the nonmetropolitan classification. The applicable SIP is listed for each and the total capacity in each designation is given in 10⁹ Btu/hr of fuel input.

The listing in Table E-2 for utility boilers has several entries for some states, one for each applicable SO₂ standard. The SIP and the total capacity under each SIP are given. The capacity units have been converted to 10⁹ Btu/hr of fuel input to make them compatible with the industrial combustor listing.

Comparison of Demand and Clean Coal Supply

Given the existing demands for coal of sufficient quality to meet various SO₂ emission limits, Tables E-1 and E-2, the quantities of raw coal in the reserve and of coal which could be cleaned by one of several processes, as determined by the RPAM model, can be compared with the existing demands.

The analysis is conducted on a regional basis with the following regional definitions:

TABLE E-1. CAPACITY OF INDUSTRIAL COAL-BURNING FACILITIES
AGGREGATED BY SIP IN EACH STATE

State/SIP Category ^(a)	SIP(b) lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr	State/SIP Category ^(a)	SIP(b) lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr
Alabama M	1.80	10.779	Nevada N	.20	1.079
Alabama N	4.00	3.922	N. Hamp.	4.00	0.000
Arizona	1.00	.385	N. Jersey M	.32	.518
Arkansas	5.00	0.000	N. Jersey N	1.60	.189
Calif. M	.80	1.234	N. Mexico	no limit	0.000
Calif. N	4.67	0.000	New York M	.40	0.000
Colorado	no limit	10.743	New York N	3.80	17.044
Conn.	.80	0.000	N. Carolina	2.30	6.540
Delaware M	1.60	0.000	N. Dakota	3.00	.351
Delaware N	no limit	0.000	Ohio M	1.40	27.447
			Ohio N	4.50	24.545
D.C.	1.60	3.081			
Florida M	1.50	0.000	Oklahoma	2.00	0.000
Florida N	6.17	0.000	Oregon M	1.60	0.000
Georgia	4.00	2.956	Oregon N	2.75	1.270
Idaho	1.60	5.035	Penna. M	.80	26.483
Illinois M	1.80	2.081	Penna. N	3.00	29.838
Illinois N	6.00	19.620	Rhode Is.	1.10	0.000
Indiana M	1.20	149.420	S. Car. M	2.30	0.000
Indiana N	no limit	10.751	S. Car. N	3.50	10.678
Iowa	6.00	7.248	S. Dakota	3.00	1.019
			Tennessee M	1.20	13.320
Kansas	3.00	0.000	Tennessee N	4.00	3.327
Kentucky M	1.20	11.527			
Kentucky N	5.00	4.456	Texas	3.00	5.497
Louisiana	5.50	.223	Utah	1.60	8.970
Maine M	2.00	0.000	Vermont	1.60	0.000
Maine N	4.00	0.000	Virginia M	1.06	.172
Maryland M	1.60	3.310	Virginia N	2.64	11.279
Maryland N	3.50	1.105	Washington	2.75	1.992
Mass. M	1.10	0.000	W. Virginia	2.60	19.187
Mass. N	2.40	0.000	Wisconsin	1.20	7.010
			Wyoming	.30	5.389
Michigan M	.80	27.774			
Michigan N	2.40	17.713	Whole U.S.		533.982
Minn. M	3.00	.289			
Minn. N	4.00	1.583			
Miss.	4.80	.371			
Missouri M	2.30	7.700			
Missouri N	5.00	6.810			
Montana	2.00	0.000			
Nebraska	2.50	.723			
Nevada M	.15	0.000			

(a) M = metropolitan

N = nonmetropolitan

(b) SIP limits are for emissions expressed as lb SO₂/10⁶ Btu. For the states which have concentration limits as percent SO₂, the limits shown were derived by postulating a nominal coal heating value for each state.

TABLE E-2. CAPACITY OF UTILITY COAL-BURNING POWER PLANTS
AGGREGATED BY SIP IN EACH STATE

State/SIP Category ^(a)	SIP, lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr	State/SIP Category ^(a)	SIP, lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr
Alabama U1	1.80	41.729	Louisiana U1	.81	0.000
Alabama U2	4.00	28.922	Louisiana U2	3.37	0.000
Arizona U	1.00	1.022	Maine U1	1.62	0.000
Arkansas U1	.97	0.000	Maine U2	2.68	0.000
Arkansas U2	2.99	0.000	Maryland U1	1.10	0.000
California U1	.58	0.000	Maryland U2	1.50	30.749
California U2	2.40	0.000	Maryland U3	2.16	0.000
California U3	4.92	0.000	Maryland U4	3.50	11.268
Colorado U1	.25	12.004	Mass. U1	1.10	0.000
Colorado U2	1.00	3.193	Mass. U2	2.45	0.000
Conn. U	.55	0.000	Michigan U1	.75	0.000
Delaware U1	1.10	0.000	Michigan U2	1.10	.135
Delaware U2	1.40	1.170	Michigan U3	1.60	19.119
Delaware U3	1.80	0.000	Michigan U4	1.70	55.860
D.C. U	.55	0.000	Michigan U5	2.40	1.224
Florida U1	.80	0.000	Minnesota U1	1.65	.324
Florida U2	1.10	0.000	Minnesota U2	2.12	.288
Florida U3	1.50	30.513	Minnesota U3	2.20	.207
Florida U4	2.78	0.000	Minnesota U4	3.10	19.365
Florida U5	6.17	12.981	Minnesota U5	4.60	7.223
Georgia U1	.24	0.000	Minnesota U6	5.60	1.628
Georgia U2	.42	0.000	Miss. U1	2.40	10.938
Georgia U3	.88	0.000	Miss. U2	4.80	.284
Georgia U4	1.86	15.716	Missouri U1	.35	0.000
Georgia U5	5.00	48.636	Missouri U2	1.00	0.000
Illinois U1	.80	0.000	Missouri U3	2.11	0.000
Illinois U2	1.00	0.000	Missouri U4	2.33	18.203
Illinois U3	1.80	87.750	Missouri U5	3.60	32.317
Illinois U4	6.00	48.990	Montana U	2.00	8.456
Indiana U1	.35	0.000	Nebraska U	2.50	10.507
Indiana U2	1.20	73.818	Nevada U1	.22	16.771
Indiana U3	2.20	7.484	Nevada U2	1.13	0.000
Iowa U1	5.00	17.562	N. Hamp. U1	1.61	0.000
Iowa U2	6.00	12.001	N. Hamp. U2	5.60	4.133
Kansas U1	.62	0.000	N. Jersey U1	.32	15.906
Kansas U2	1.23	0.000	N. Jersey U2	1.50	4.968
Kansas U3	3.00	18.793	N. Mexico U	.33	20.428
Kentucky U1	1.20	34.340	New York U1	.33	0.000
Kentucky U2	1.80	3.299	New York U2	2.16	0.000
Kentucky U3	4.00	3.186	New York U3	2.66	0.000
Kentucky U4	5.20	30.470	New York U4	3.80	24.028
Kentucky U5	6.00	25.299	M. Car. U	2.30	103.644

TABLE E-2. Continued

State/SIP Category ^(a)		SIP, lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr	State/SIP Category ^(a)		SIP, lb SO ₂ /10 ⁶ Btu	Capacity, 10 ⁹ Btu/hr
N. Dakota	U	3.00	11.255	W. Va.	U3	2.80	0.000
Ohio	U1	.50	8.553	Wisconsin	U1	.30	0.000
Ohio	U2	1.20	19.620	Wisconsin	U2	.80	0.000
Ohio	U3	1.40	28.441	Wisconsin	U3	1.20	8.975
Ohio	U4	2.00	16.752	Wyoming	U	.30	.466
Ohio	U5	2.50	21.519				
Ohio	U6	3.00	24.314	Whole U.S.			1523.845
Ohio	U7	3.50	1.800				
Ohio	U8	4.50	11.862				
Ohio	U9	5.00	2.592				
Ohio	U10	5.50	10.458				
Ohio	U11	6.00	14.506				
Ohio	U12	7.00	.572				
Ohio	U13	8.00	11.637				
Ohio	U14	9.00	23.400				
Oklahoma	U	2.00	.311				
Penna.	U1	.60	34.805				
Penna.	U2	2.30	7.985				
Penna.	U3	4.00	109.618				
Rhode Is.	U	1.10	0.000				
S. Car.	U1	2.30	15.375				
S. Car.	U2	3.50	27.353				
S. Dak.	U	3.00	6.390				
Tenn.	U1	1.20	28.667				
Tenn.	U2	3.00	18.329				
Tenn.	U3	5.00	38.657				
Texas	U	.75	19.591				
Utah	U	1.60	7.988				
Vermont	U	1.19	0.000				
Virginia	U1	1.32	0.000				
Virginia	U2	1.83	0.000				
Virginia	U3	2.55	0.000				
Virginia	U4	2.80	0.000				
Virginia	U5	3.20	0.000				
Virginia	U6	5.39	0.000				
Wash.	U1	1.20	11.970				
Wash.	U2	1.71	0.000				
W. Va.	U1	1.42	3.240				
W. Va.	U2	2.16	0.000				

(a) U = Utility boilers.

User Regions

<u>Number</u>	<u>Description</u>
1	Northeastern United States
2	Southeastern United States
3	Alabama and Neighboring States
4	Eastern Midwest
5	Western Midwest
6	Western United States
7	Continental United States

Coal Producing Regions

<u>Number</u>	<u>Description</u>
1	Northern Appalachian
2	Southern Appalachian
3	Alabama
4	Eastern Midwest
5	Western Midwest
6	Western
7	U.S. Combined

A "coal use" model was developed which assumes that a demand group will use coal with the highest sulfur level possible to meet its SO₂ emission standard. As these reserves are depleted, the group then uses coal with lower and lower sulfur levels. This procedure would be approximated in reality (over a long time period) if the cost of coal increases with a lowering sulfur content. Thus, a large capacity user with a fairly nonrestrictive SIP, e.g., nonmetropolitan Ohio, will ultimately be using the same reserves as a smaller capacity user with a more restrictive SIP, e.g., nonmetropolitan Maryland. The model is run until all of the coal in the region is consumed with the various users running out of coal (depending on supply, SIP, and demand) at various times. The model output is the number of years each demand group can use coal before the reserve is exhausted of coal capable of meeting the SIP for that demand group. The years of supply is obtained from the total suitable reserve, in Btu, divided by the current annual rate of consumption, in Btu/year.

The model is run first with raw coal as the supply, then successively with coal cleaned by one of eight processes as the supply. The coal cleaning processes are defined as follows.

- A. Physical coal cleaning using minus 1-1/2-inch coal separated at 1.6 s.g.
- B. Physical coal cleaning using minus 3/8-inch coal separated at 1.6 s.g. if this produced coal to meet the standard; otherwise, 1.3 s.g. was used for separation. An operating penalty of 1 percent energy loss was assumed.
- C. Meyers process: for raw coal with greater than 0.2 percent pyritic sulfur, the level of pyritic sulfur is reduced to 0.2 percent. No sulfur reduction takes place if the raw coal pyritic sulfur level is less than 0.2 percent. A 5 percent energy loss was assumed plus an operating penalty of 2 percent energy loss and a weight loss of 10 percent.
- D. Gravichem process: crush coal to 14-mesh top size; separate at 1.3 s.g.; treat sink with Meyers process (with the same energy and weight loss as in C); combine the float and the processed sink.
- E. 95 percent pyritic sulfur and 20 percent organic sulfur removed with 10 percent energy loss plus an operating penalty of 2 percent energy loss and a weight loss of 15 percent.
- F. Physical cleaning using minus 3/8-inch coal at 1.3 s.g., no operating penalty.
- G. 95 percent pyritic sulfur and 40 percent organic sulfur removed with 30 percent energy loss.
- H. 70 percent organic sulfur removed.

Results

The results of the model runs comparing the quantities of suitable coal in each region, as obtained from the RPAM model, with the demand of each SIP group in each region are summarized in Table E-3. The first column of Table E-3 gives the SIP ranges. The second column gives the total capacity, in 10^9 Btu/hr of fuel input, of all the facilities in the region which operate under SIP's in the indicated range. The total capacity is converted to annual coal

TABLE E-3. INFLUENCE OF COAL CLEANING ON SUPPLY OF COAL TO MEET
EXISTING INDUSTRIAL AND UTILITY DEMANDS

SIP Range lb SO ₂ / 10 ⁶ Btu	Aggregate Coal Capacity, 10 ⁹ Btu/hr	Annual Coal Demand (a)		Total Availability, Btu ÷ Current Annual Use, Btu/yr (or Years Availability)										
		10 ⁶ tons	10 ¹⁵ Btu	Cleaning Process (b)										
				Raw	A	B	C	D	E	F	G	H		
(1) Northeastern United States														
0.32	16.42	3.64	0.08	1	19	264	301	271	363	225	328	119		
0.50-0.60	43.35	9.54	0.21	19	100	358	413	378	641	312	591	244		
0.80	26.48	4.54	0.10	109	504	668	663	667	641	644	645	440		
1.20-1.50	115.63	24.09	0.53	304	504	668	663	667	641	644	645	440		
1.60-4.00	291.03	60.45	1.33	526	671	668	663	667	641	644	645	705		
4.50	36.40	6.82	0.15	992	738	668	663	667	641	644	645	928		
5.00-9.00	67.29	14.54	0.32	1985	1160	668	663	667	641	826	645	928		
Total	596.64	123.62	2.72											
(2) Southeastern United States														
1.06-6.17	620.31	131.36	2.89	318	320	320	320	320	320	319	320	319		
(3) Alabama and Neighboring States														
1.20-5.00	297.06	63.64	1.40	53	53	53	53	53	53	53	53	53		
5.50-6.17	13.20	2.73	0.06	56	53	53	53	53	53	53	53	53		
Total	310.26	66.37	1.46											
(4) Eastern Midwest														
0.80-1.20	312.99	60.00	1.32	22	40	56	120	91	149	52	133	62		
1.60-1.80	168.43	36.82	0.81	59	116	170	157	166	193	160	181	103		
2.12-2.40	26.91	5.00	0.11	594	846	1130	1512	1327	1808	1083	1755	619		
3.00-3.10	19.65	4.09	0.09	594	1256	1958	1936	1999	1808	1697	1755	1721		
4.00-6.00	142.45	30.00	0.66	941	2003	1958	1936	1999	1808	1697	1755	1974		
***** (c)	10.75	1.82	0.04	28,385	7544	4347	1936	1999	1808	9554	3690	7136		
Total	681.20	137.73	3.03											

TABLE E-3. (Continued)

SIP Range lb SO ₂ / 10 ⁶ Btu	Aggregate Coal Capacity, 10 ⁹ Btu/hr	Annual Coal Demand (a)		Total Availability, Btu ÷ Current Annual Use, Btu/yr (or Years Availability) Cleaning Process (b)									
		10 ⁶ tons	10 ¹⁵ Btu	Raw	A	B	C	D	E	F	G	H	
(5) Western Midwest													
0.75	19.59	4.09	0.09	17	23	147	452	404	477	208	520	203	
2.00-3.00	51.73	12.73	0.28	193	232	312	574	482	583	303	529	203	
3.60	32.31	7.27	0.16	193	232	312	574	482	583	343	529	203	
5.00	24.37	5.00	0.11	234	760	1008	601	834	583	756	529	585	
6.00	19.24	3.64	0.08	234	883	1008	601	834	583	756	529	693	
Total	157.26	32.73	0.72										
(6) Western United States													
0.20	1.07	0.18	0.004	133	1612	2972	3484	3527	4268	2546	3920	2381	
0.22	16.77	3.64	0.08	441	1612	2972	3484	3527	4268	2546	3920	2381	
0.25	12.00	2.73	0.06	924	1854	2972	3484	3527	4268	2546	3920	3318	
0.30-0.33	26.28	5.45	0.12	1173	2355	2972	3484	3527	4268	2546	3920	4214	
0.80-*****	81.27	16.36	0.36	9484	8659	7954	7580	7548	7008	8265	7262	7621	
Total	137.40	28.36	0.624										
(7) Continental United States													
0.20	1.07	0.18	0.004	140	887	934	940	940	940	901	940	906	
0.22	16.77	3.64	0.08	442	887	934	940	940	940	901	940	906	
0.25-0.33	56.64	11.82	0.26	762	887	934	940	940	940	901	940	906	
0.50-4.00	1575.68	325.91	7.17	771	887	934	940	940	940	901	940	906	
4.50-5.00	162.99	34.09	0.75	771	991	934	940	940	940	901	940	906	
5.20-6.00	174.57	36.82	0.81	779	991	934	940	940	940	901	940	906	
6.17	12.98	2.73	0.06	1389	991	934	940	940	940	901	940	1042	
7.00-*****	57.10	11.36	0.25	6952	2187	1141	940	940	940	2326	940	2124	
Total	2057.82	426.55	9.384										

- (a) Capacity converted to demand assuming 3,854 hours of operation per year (load factor = 0.44) for industrial combustors, and 4,818 hours/year (capacity factor = 0.55) for utility boilers.
- (b) See text for definition of cleaning processes.
- (c) ***** = No limit on SO₂ emissions.

demand by assuming a load factor of 0.44 for industrial facilities and a capacity factor of 0.55 for utility boilers. The annual coal demand is expressed in millions of tons per year (assuming 22×10^6 Btu/ton as an average) in the third column of Table E-3 and in quadrillions of Btu per year in the fourth column.

The model output results, the ratio of the total suitable supply, in Btu, divided by the current rate of use, Btu/year (or years of supply under the indicated SIP's and at the indicated rate of consumption), are given in the following nine columns. Each of these columns represents the results if one type of coal, either raw, i.e., uncleaned coal, or coal cleaned by one of the eight processes defined above, is used to satisfy the demands. For example, consider the first row of data for the northeastern United States, Region 1. The facilities in this region which are operating under a SIP limit of $0.32 \text{ lb SO}_2/10^6 \text{ Btu}$ have a combined capacity of 16.42 billion Btu per hour. At the assumed load factors, these facilities require 0.08×10^{15} Btu per year or 3.64×10^6 tons of coal per year. The RPAI reserve file shows that the reserve in the northern Appalachian region contains about 4.5 million tons of raw coal sufficiently low in sulfur content to be burned under this SIP. This coal will last about 1.24 years at the current rate of demand. This is rounded to one year as shown in the first entry under "Raw". If coal cleaning Process A (physical coal cleaning using 1-1/2-inch M coal separated at 1.6 s.g.) is used to clean suitable portions of the reserve, nearly 70 million tons of coal could be produced which could be burned in compliance with a SIP of $0.32 \text{ lb SO}_2/10^6 \text{ Btu}$. This would last this group of users 19 years as shown under "A" in Table E-3. Similarly, the use of coal cleaning Process B (3/8-inch M coal separated at 1.6 s.g. or 1.3 s.g.) could increase the supply to 264 years (960 million tons), Process C (Meyers process) could increase the supply to 301 years (1095 million tons), etc. We see that, for example, Process C could increase the coal supply by a factor of 240 over that of raw coal for this group of users. The same type of information is presented in Table E-3 for each SIP range in Region 1 and for each of the other regions.

The value of coal cleaning in increasing supplies of coal for compliance with strict SO_2 regulations may be seen in Figure E-1, which is a visual representation of some of the results for the same region. The results are shown in the form of bar charts. In each chart the ratio of total

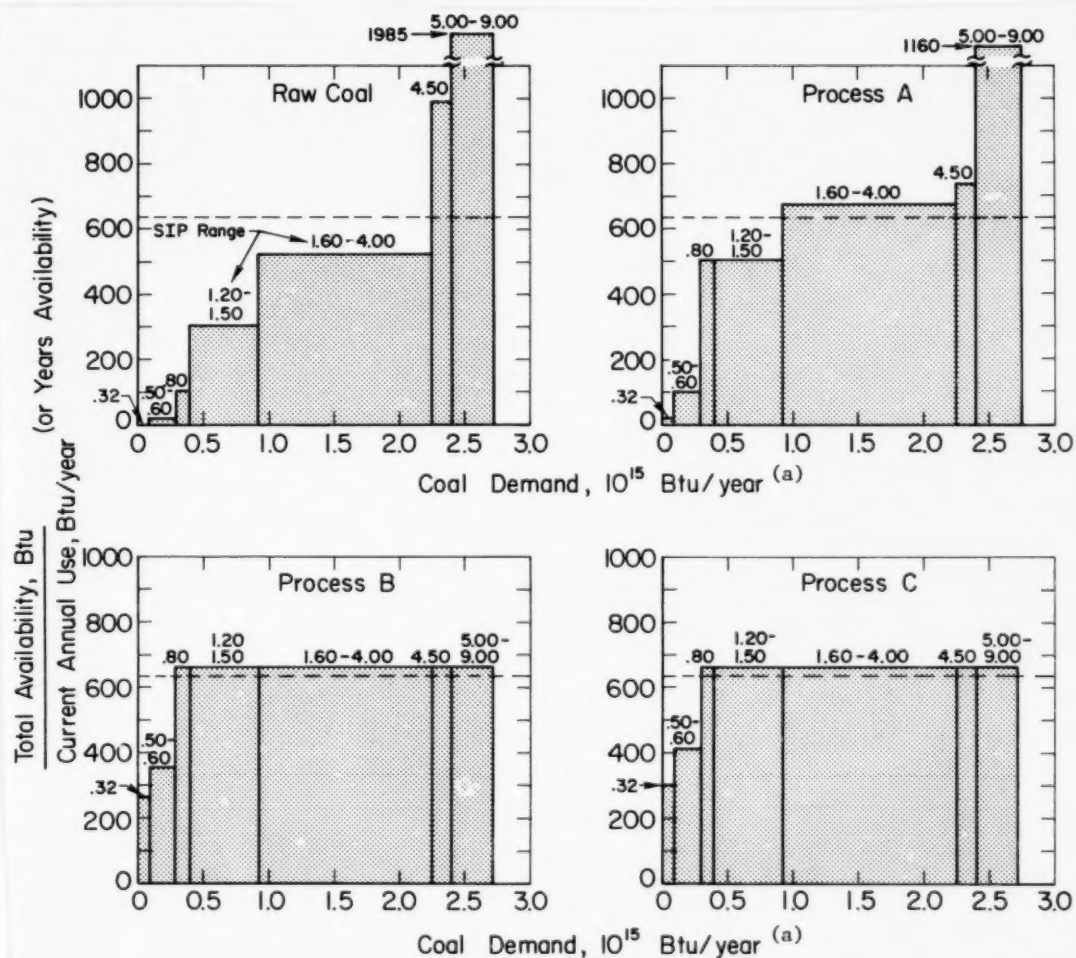


FIGURE E-1. INCREASE IN THE QUANTITIES OF SIP-COMPLIANCE COAL ACHIEVABLE BY COAL CLEANING--NORTHEASTERN U.S.
(see text for definition of processes)

(a) Northeast U.S. utility and industrial coal demand met by coal produced in the Northern Appalachian region.

coal to annual demand (or years of availability) is plotted against annual demand. The width of each bar represents the aggregate demand of all facilities in the region which operate under SIP's in the range shown at the top of the bar, while the height of the bar represents the number of years that compliance coal would be available if used at the current rates. The area of each bar represents the total quantity, in 10^{15} Btu, of coal in the reserves of the Northern Appalachian Region which can satisfy the SIP's in the indicated range. The horizontal dotted line shows the years of coal availability, at the current rates, if used without regard to sulfur content, and the area under the dotted line represents the total Btu's of coal in the northern Appalachian reserve.

The four bar charts show the results for raw coal and for coal produced by three of the cleaning processes as defined previously. The charts show clearly the usefulness of these coal cleaning processes in producing coal to satisfy SIP's. The chart for raw coal shows that very little coal in the region could be burned in compliance with a SIP of 0.32 (New Jersey, industrial, metropolitan areas), and only limited quantities of raw coal are sufficiently low in sulfur content that SIP's of 0.5 to 0.8 could be met. On the other hand, the charts for coal cleaned by Processes A, B, and C show progressively increasing quantities (increases in the shaded areas) of coal in compliance with low SIP's which can be produced by these cleaning processes.

Similar bar charts are shown in Figure E-2 for Region 5, the Western Midwest Region. The ability of coal cleaning to increase supplies of coal to meet strict SIP's is equally apparent in this series of charts.

The ability of coal cleaning to increase supplies of coal to meet SIP's, of course, is reflected as well in the results for the entire U.S., Region 7, Table E-3. In this case the full increase in supply for the most restrictive SIP's is not discernible because, for even the simplest cleaning process, the increase in supply is large enough that other groups of users with less restrictive SIP's but with greater demand ultimately draw from the same coal as that supplying the most restrictive SIP's, as shown in Table E-3.

Also in Table E-3, we see that in Region 2, Southeastern United States, and in Region 3, Alabama and neighboring states, all of the coal-burning facilities are grouped together, except for the raw coal use in Region 3. There are two reasons for this result. The first is that in each region there are groups of large consumers under relatively nonrestrictive SIP's e.g., Georgia, U5, and Tennessee, U3 (see Table E-2), both with SIP's of

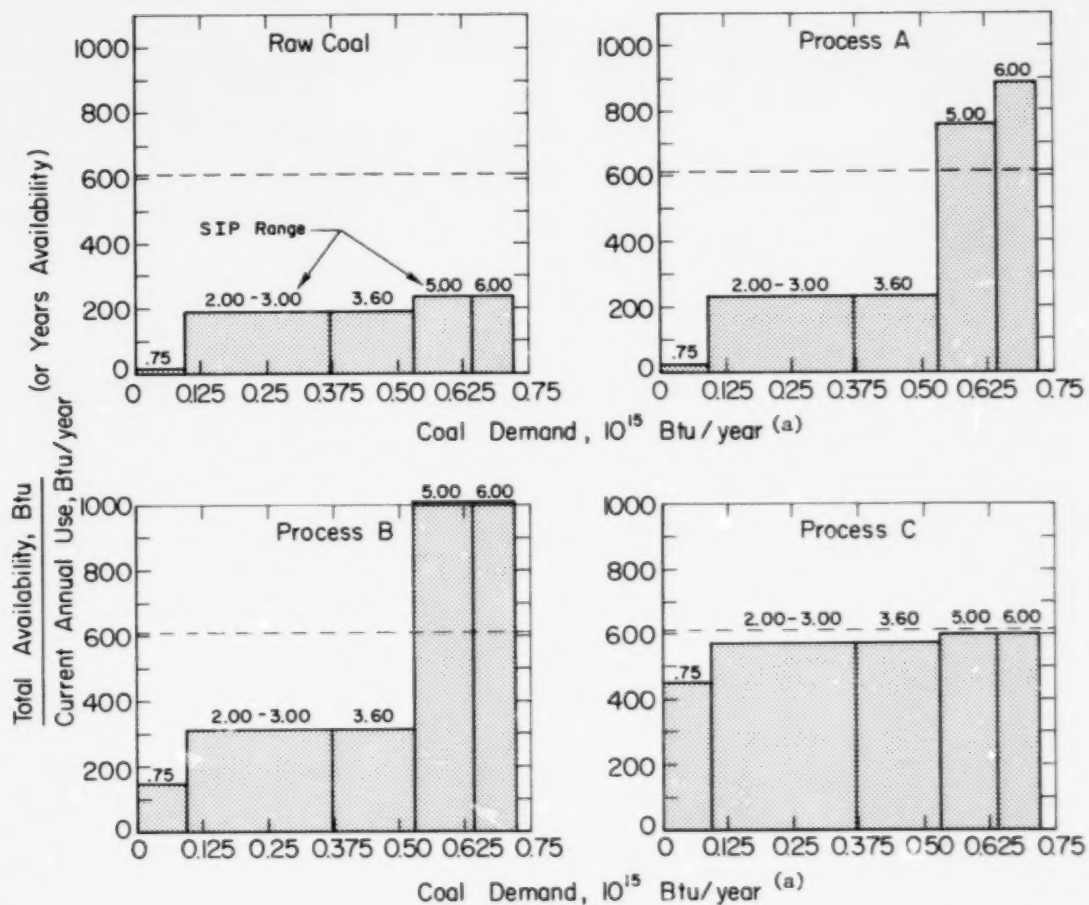


FIGURE E-2. INCREASE IN THE QUANTITIES OF SIP-COMPLIANCE COAL ACHIEVABLE BY COAL CLEANING--WESTERN MIDWEST U.S.

(a) Western Midwest regional utility and industrial coal demand met by coal produced in the same region.

5.0 lb SO₂/10⁶ Btu, which at some point in time use up the coal which is just good enough to meet the SIP and then coal of lower sulfur content is used together with groups of facilities using coal to meet more restrictive SIP's. The second reason is that the most restrictive SIP under which coal is actually being used is 1.06 in Region 2 and 1.20 in Region 3. The demand of users under these SIP's is sufficiently low and the supply of compliance coal is sufficiently high that these users do not run out of coal before the rest of users. We can see further from the data of Table E-3 for Regions 2 and 3 that coal cleaning apparently does not change the supply of compliance coal markedly. Again, there are two reasons for this. The first is that, because large users under high (less restrictive) SIP's end up using coal of lower sulfur content than required, the increase in supply of coal with reduced sulfur content produced by cleaning cannot be detected by the model as designed. If the large users under high SIP's were to acquire coal of quality just sufficient to meet their SIP's from the northern Appalachian producing region, the increased supply of coal with reduced sulfur content produced by coal cleaning would be observed. The second reason is that coal cleaning, although still a useful process for coals produced in Regions 2 and 3, is not as effective in reducing the sulfur content of these coals as it is for coals of other regions. This is apparent from the data of Tables 8 and 9 in Section 3 of this report.

References for Appendix E

- (E-1) "Major Fuel Burning Installation (MFBI) Coal Conversion Report" (a computer tape based on responses - in 1975 - to Questionnaire designated FEAC-602-5-0, Federal Energy Administration (now Department of Energy), Washington, D.C.
- (E-2) Paddock, R. E., and McMann, D. C., "Distributions of Industrial and Commercial-Institutional External Combustion Boilers", EPA 650/2-75-021 (February, 1975).
- (E-3) Energy Data System (EDS), (a computer file of location and capacity of coal-fired utility boilers as of 1977), Industrial Environmental Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

APPENDIX F

AIR QUALITY CONSIDERATIONS

APPENDIX F

AIR QUALITY CONSIDERATIONS

This Appendix consists of a paper, prepared by Teknekron under subcontract, summarizing studies of atmospheric SO_2 -sulfate transformation and long-range transport. The implications of the results for control strategies are discussed. The text is presented verbatim.

A SUMMARY OF STUDIES OF ATMOSPHERIC SO_2 -SULFATE TRANSFORMATION
AND LONG-RANGE TRANSPORT: INITIAL RESULTS AND IMPLICATIONS FOR CONTROLS

Preface

Several regional air-quality studies have produced evidence that in some regions of the United States violations of air quality standards for SO_2 and/or TSP may be caused by emissions of SO_2 at sources several hundred kilometers upwind. The long-range impact of SO_2 emissions can occur during periods in which persistent winds along a path between source and receptor areas transport the SO_2 and associated sulfates, which may be produced by one or more SO_2 -sulfate conversion mechanisms.

In this paper we describe several of the ongoing regional air-quality research programs that seek to characterize SO_2 transformation-transport systems. A key goal of these research programs is the development of quantitative source-receptor relationships for specific geographic areas and the forecasting of pollutant episodes caused by upwind SO_2 emissions.

In terms of environmental policy the objectives of current research on SO_2 transformation and transport include establishment of criteria for (1) modifying pollutant-emission limitations at existing and planned SO_2 sources in order to prevent violation of air quality standards or PSD increments at downwind locations, and (2) siting new SO_2 sources to avoid locating these

plants along probable long-range transport paths, where the additive impacts of source emissions can cause "source intensification". In cases where clusters of coal-burning plants contribute to violations of air quality standards in remote downwind areas, permissible levels of pollutant emissions may have to be reduced.

Restrictions upon the interstate transport of pollutants, pursuant to the 1977 Amendments to the Clean Air Act, could affect the degree of SO₂ control required for upwind sources that contribute to interstate transport. Current allowable emission limitations at these sources, now imposed to prevent violations of local standards, may be made more stringent in order to prevent the violation of standards that these sources cause in remote areas. Thus supplemental controls may be necessary. Since violations attributable to long-range transport occur intermittently, and possibly predictably, the question arises: If they are required, could supplementary controls be applied intermittently rather than continuously? Although the 1977 Amendments clearly prohibit the use of intermittent controls as a means of limiting concentrations locally (in the vicinity of the source), the use of some form of intermittent controls to prevent pollution episodes that occur remotely--and intermittently--is not obviously precluded by the Act. We explore this question below in the context of the results of the transformation-transport studies that we describe in this paper.

Introduction to the Problem

The Environmental Protection Agency has promulgated national ambient air quality standards (NAAQS), formulated as allowable levels of concentrations, and regulations limiting emissions of criteria pollutants for specified source categories. In order to ensure the attainment of NAAQS, emissions from coal-burning utility boilers must conform either to current EPA new source performance standards (NSPS), expected to become more stringent in forthcoming revisions, or to state implementation plans (SIP's) depending upon the age and location of the plant.

Nonattainment regions for SO_2 or TSP are areas in which the NAAQS for these pollutants have been exceeded. The 1977 Amendments to the Clean Air Act require that nonattainment regions be brought into compliance by 1982. EPA recently reported that of the 3215 counties in the U.S. all or part of 424 counties violated TSP standards and all or part of 108 counties violated SO_2 standards. Figure F-1 indicates counties in the eastern United States with violations or near-violations of TSP and SO_2 standards. The Act also requires that new emissions in nonattainment areas be "offset" by concurrent emission reductions from existing sources. This offset policy applies to sources that increase a pollutant level in a nonattainment area--even if the source is located in an "attainment" area.

In "clean" areas--where the air is already cleaner than the NAAQS--standards are more stringent than the NAAQS, reflecting a policy of ensuring the prevention of significant deterioration (PSD). A pollutant source will be subject to PSD requirements if it contributes to degradation of air quality in a clean area--even if the source is not located in a clean area.

Emissions of SO_2 are converted to various species of sulfates which take the form of fine particulates. The extent of these conversions depends largely upon several conversion mechanisms (see Table F-1) and the percentage of SO_2 that is removed by dry or wet deposition. Although some health risk has been associated with atmospheric sulfates, EPA awaits further information relating health effects to speciation of sulfates before sulfates can be listed as a criteria pollutant. Notwithstanding this fact, five states have established their own ambient sulfate standards. In California, for example, the Southern California Air Quality Management District limits the 24-hour maximum sulfate concentration to $25 \mu\text{g}/\text{m}^3$. If EPA establishes an ambient air standard for respirable, or fine, particulates--a possibility that EPA is considering--sulfate concentrations would be affected, since sulfates are among the most significant respirable particulates.

The development of control strategies for reducing sulfate levels requires establishing and verifying source-receptor relationships between SO_2 emissions and sulfate concentrations in areas downwind of these emissions. Relating sulfate concentration to precursor emissions temporarily, spatially, and



Counties with one or more stations in which NAAQS are violated (circled) or almost violated (i.e., annual average concentrations as percentages of NAAQS are $\geq 90\%$ for TSP, $\geq 50\%$ for SO_2).

● TSP (total suspended particulates)

▲ SO_2

* Both TSP and SO_2

FIGURE F-1. COUNTIES WITH AN SO_2 AND/OR TSP AIR QUALITY MAINTENANCE PROBLEM IN 1975

TABLE F-1. MECHANISMS BY WHICH SULFUR DIOXIDE IS CONVERTED TO SULFATES

<u>Mechanism</u>	<u>Overall Reaction</u>	<u>Factors on which Sulfate Formation Primarily Depends</u>
1. Direct photo-oxidation	$\text{SO}_2 \xrightarrow[\text{water}]{\text{light} \rightarrow \text{oxygen}} \text{H}_2\text{SO}_4$	Sulfur dioxide concentration, sunlight intensity
2. Indirect photo-oxidation	$\text{SO}_2 \xrightarrow[\text{hydroxyl radical (OH), HO}_2, \text{RO}_2, \text{radicals}]{\text{smog, water, NO, organic oxidants}} \text{H}_2\text{SO}_4$	Sulfur dioxide concentration, organic oxidant concentration, OH, NO _x , HO ₂ , RO ₂
3. Air oxidation in liquid droplets	$\text{SO}_2 \xrightarrow{\text{liquid water}} \text{H}_2\text{SO}_3$ $\text{NH}_3 + \text{H}_2\text{SO}_3 \longrightarrow \text{NH}_4^+ + \text{SO}_4^{2-}$	Ammonia concentration
4. Catalyzed oxidation in liquid droplets	$\text{SO}_2 \xrightarrow[\text{heavy metal ions}]{\text{oxygen, liquid water}} \text{SO}_4^{2-}$	Concentration of heavy metal (Fe, V, Mn) ions
5. Catalyzed oxidation on dry surfaces	$\text{SO}_2 \xrightarrow[\text{carbon particle}]{\text{oxygen water}} \text{H}_2\text{SO}_4$	Carbon-particle concentration (surface area)

aerometrically, is complicated. In some cases, reducing the emissions of SO_2 has not reduced the concentration of sulfates, either locally or remotely; in other areas local observations have shown an inverse relationship: lowest SO_2 emissions, but highest sulfate concentrations, during the summer.

Table F-1 indicates the five major mechanisms by which SO_2 is converted to sulfates and the major factors upon which these mechanisms depend. (F-1)* The first two mechanisms are homogeneous or first order. That is, the percentage reduction of product sulfates will equal the percentage reduction in precursor SO_2 . The last three reactions, however, are heterogeneous or zero order, implying that the percentage reduction in sulfate may be much smaller than the percentage reduction in SO_2 . In these reactions the control of pollutants other than SO_2 that increase the rates of SO_2 -sulfate conversion, such as ammonia, some trace-metal ions, and carbon particles (fly ash), is important.

Conversions by means of each of the mechanisms listed in Table F-1 accelerate in the presence of water. The first two mechanisms require sunlight, while the second mechanism is promoted by certain organic oxidants, radicals (particularly OH), and NO_x .

Tall stacks normally permit greater dilution of SO_2 and product sulfates, and hence lower concentrations of these pollutants at the source. An exception occurs when the plume is trapped below an elevated-temperature inversion layer. On the other hand, the rate of SO_2 surface deposition is decreased so that there is more time for SO_2 -sulfate conversions to take place, especially when plumes from tall stacks become trapped above, or imbedded within, an inversion layer.

Among the meteorological conditions determining the long-range transport of primary and secondary pollutants, wind persistence and velocity are particularly important, especially where multiple pollutant sources are located along the wind trajectory. Stagnating air masses are also important: where there are no fronts or precipitation for at least four days, the stagnation can lead to a considerable accumulation of local emissions.

Regional air-quality research programs have documented cases in which source intensification and long-range transport of SO_2 and sulfates (chemically transformed from SO_2) significantly raise the sulfate and TSP levels along the transport path. Striking examples include the arrival of sulfates

* References for Appendix F are given on page 345.

in Scandinavia from the United Kingdom, and in the Commonwealth of Pennsylvania from Ohio and West Virginia. Current and planned research is directed towards identifying additional source-receptor systems. Furthermore, programs are developing and verifying complex numerical models to determine the extent to which such models may be used to characterize these systems and to predict concentrations of SO_2 and sulfates at receptor areas as a function of SO_2 emissions from multiple sources. To verify these systems, research programs are continuing measurements of pollutant emissions and concentrations and essential aerometric parameters.

Some studies suggest that emissions of not only SO_2 but also particulates--especially fine particulates--must be subject to additional controls in situations where incremental downwind concentrations must be prevented. Particulates are implicated in the SO_2 -sulfate transformations because they may serve as efficient catalysts in the oxidation of SO_2 .^(F-2)

Summary of Research Programs on SO_2 -Sulfate Conversion and Transport

To indicate the status and goals of ongoing research programs relating to long-range transport of SO_2 and sulfates resulting from coal combustion, we summarize three of the major programs: (1) Regional air quality analyses that are part of the Teknekron-EPA Integrated Technology Assessment (ITA) of Electric Utility Energy systems, (2) EPRI's Sulfate Regional Experiment (SURE), and (3) EPA's Midwest Interstate Sulfur Transformation and Transport (MISTT) program.

The Teknekron-EPA Regional Air Quality Studies

The major components of the ITA Regional Air Quality analyses include:

- Forecasts of the counties that will have high emissions from utility and industrial boilers
- Analysis of historical meteorological data to yield preferred paths for the downwind transport of emissions from source locations

- Analysis of emissions, air quality, and meteorological data to develop source-receptor relationships for SO₂ emissions and sulfate concentrations
- Application of air quality models to determine ambient concentrations of SO₂, NO_x, particulates, and sulfates

Teknekron is using its long-range air quality analysis methodologies to support EPA in explaining observed measurements of high sulfate concentrations and in forecasting where similar high sulfate levels may be expected in the future. EPA will utilize these results to develop power-plant siting criteria and emission-control strategies that will be responsive to both energy needs and environmental protection.

Findings to date indicate six areas of the nation to be "hot spots"--high emission areas--by 1995 under a number of alternative energy and environmental policies. These include the: (1) upper Ohio River, (2) lower Ohio River, (3) Great Lakes - Canada, (4) Gulf Coast, (5) Appalachian, and (6) Rocky Mountain regions. Analysis shows that Air Quality Control Regions (AQCR's) with high emission densities are either clustered together in several areas or are oriented along the preferred paths for long-range transport, a condition which gives rise to "source intensification".^(F-3) "Source intensification" describes a situation wherein pollutant concentrations from each succeeding emissions source in a continuous line of sources is superimposed on concentrations attributed to all the preceding sources.

Results have clearly indicated that under some aerometric conditions persistent winds may transport high levels of pollutants to remote areas, causing, in some instances, significant increases of sulfate levels and, consequently, violations of air quality standards for TSP. For example, it was found that high rural sulfate concentrations were to the north of the high SO_x emission density AQCR's in the lower Ohio River Basin and to the northeast of the high SO_x emission density AQCR's in the upper Ohio River Basin. These directional orientations were in agreement with the most frequent meteorological conditions conducive to long-range transport in these two parts of the basin.

In one case study results indicate that under certain conditions, air-pollutant transport systems in the Ohio River Basin are responsible for significant increases of sulfate (and therefore TSP) concentrations in the Commonwealth of Pennsylvania. These results raise important questions relating to environmental policy in the Ohio River Basin. We summarize the background of these particular studies and some preliminary results that identify sources of emissions of air pollutants outside of Pennsylvania and adverse local and regional-scale dispersion patterns responsible for transporting these pollutants to parts of Pennsylvania.^(F-4) These results may point to the need for a policy of stricter emissions limitations for upwind sources, a policy which can be implemented by virtue of Congressional mandates in the 1977 amendments to the Clean Air Act: (1) to revise implementation plans for nonattainment areas (§172), and (2) to restrict the interstate transport of pollutants (§§110[a][E] and 126).

Long-Range Transport of Pollutants to Pennsylvania

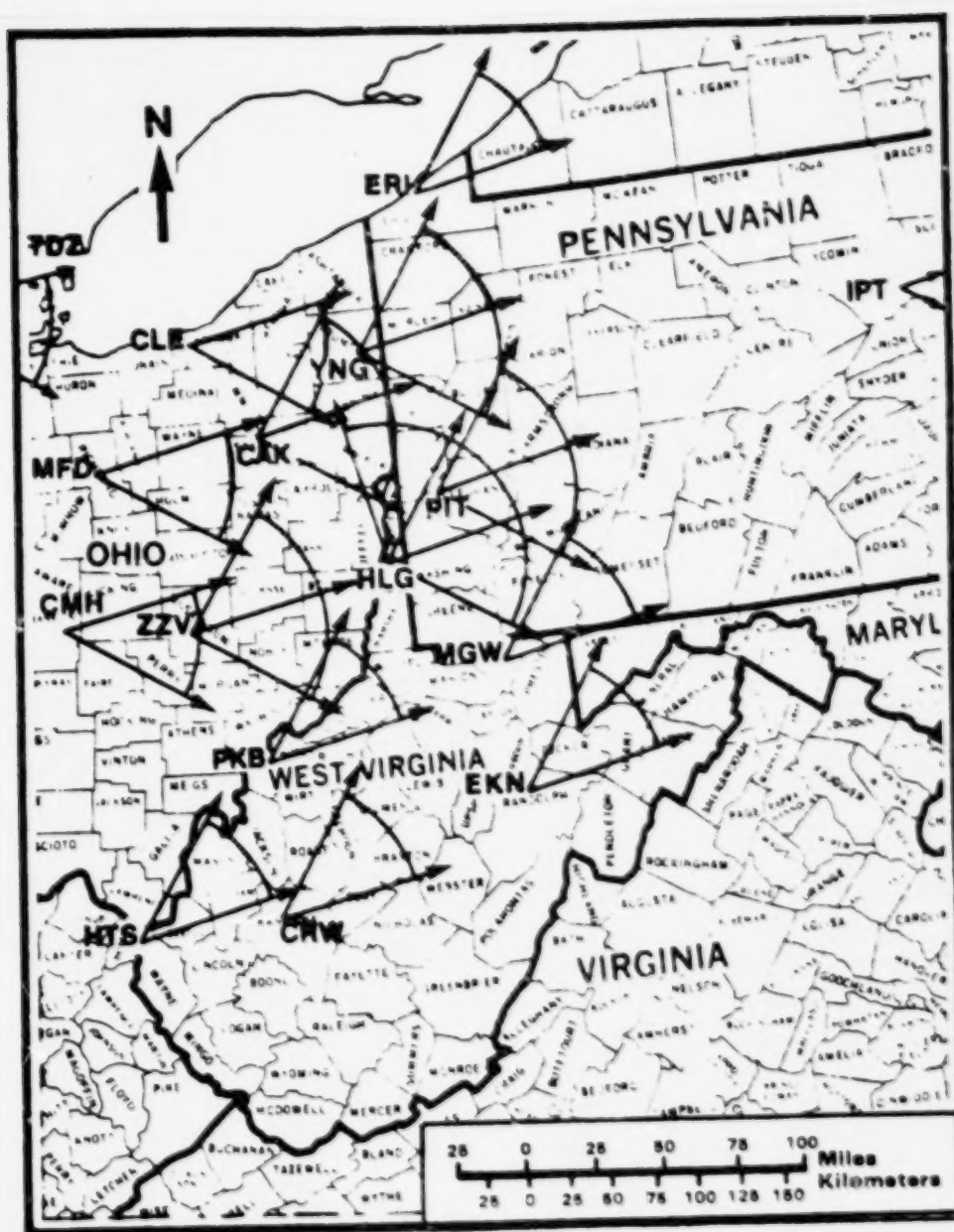
Background. In 1976 EPA notified Pennsylvania that every county in the state was in violation of the national air quality standards for total suspended particulates (TSP), and that Pennsylvania should therefore revise its State Implementation Plan (SIP). But there was some question whether pollutants from Pennsylvania emission sources were actually responsible for the violations. In 1974, using the limited air quality data then available, Rubin and Dunlap^(F-5) concluded that high levels of TSP were being transported into Allegheny County, Pa. from outside sources by prevailing westerly winds. Only a small local contribution would bring the county over the secondary TSP standard. Then, in 1977, results of Teknekron's analysis indicated that, because of frequent meteorological conditions and the spatial distribution of emission sources, high levels of pollutants were being carried into Pennsylvania by long-range transport from Ohio and West Virginia power plants (see Figure F-2). The Commonwealth of Pennsylvania called for revision of the Ohio SIP and asked the EPA to support detailed investigations of the impact of emissions from Ohio, as well as the impact of the proposed relaxation of sulfur dioxide emission limits for the Harrison and Mitchell power plants in West Virginia.

EPA responded by asking Teknekron to conduct a detailed study of the Ohio-West Virginia-Pennsylvania border area. In addition, in response to many inquiries to EPA about the impact of existing and proposed power plants in the lower Basin states, the Agency asked Teknekron to make an in-depth analysis of that area and particularly of two plants to be built between Louisville and Cincinnati.

Preliminary Results of the Upper Basin Study

Teknekron focused on quantifying the frequency of long-range-transport conditions in the three-state border area and on determining the correlation between these conditions and TSP levels, especially when the latter exceeded the 24-hour standards and could be attributed to significant levels of sulfate. Defining a "significant" contribution of sulfate to TSP as 10 percent or more, Teknekron found that sulfate accounted for about 20 to 40 percent of the TSP measured during major pollutant episodes in Pennsylvania. The conclusion: outside sources were contributing significantly to Pennsylvania's air quality problems.

Considering five to ten years of conventional National Weather Service data and one to two years of special meteorological tower data for a large number of locations, Teknekron found that extremely persistent winds in the area blow most frequently toward Pennsylvania from both Ohio and West Virginia (see Figure F-3), and that these conditions occur at most locations conservatively at least 30 times per year. (Extremely persistent winds are known to transport pollutants over considerable distances while concentrating the impact within a rather narrow sector downwind. They also provide one of the simplest source-receptor situations in which impacts downwind can be ascribed to specific sources upwind.) From spatial correlations of these winds, Teknekron found that pollutants in the border area may be transported as far as 300 kilometers from Huntington, West Virginia, to western Pennsylvania. The frequency distribution of winds 600 meters above ground at the Greater Pittsburgh airport showed that the winds blow from Ohio and West Virginia about 74 percent of the time but toward those locations only about 25 percent of the time.



Note: The arrows indicate schematically the direction in which the wind persists for six hours duration within a 96 mile (155 km) radius from the origin.

FIGURE F-3. SECTORS OF EXTREMELY PERSISTENT WINDS IN THE UPPER OHIO RIVER BASIN AREA

The large sulfate and TSP data base compiled by Teknekron comprised information from the Sulfate Regional Experiment (SURE I)^(F-6), the Pennsylvania Department of Environmental Resources (DER), and EPA Regions III and V. The SURE I data demonstrated that, for about one-quarter of the days per year, 24-hour average sulfate levels of about five micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) to over $30 \mu\text{g}/\text{m}^3$ at Wheeling were associated with extremely persistent winds directed toward Pennsylvania. Moreover, Wheeling's monthly average sulfate levels exceeded the Pennsylvania sulfate standard for every month in a 12-month period of 1974-75. From the DER data for a site near the towns of Sharon and Farrell, Pa., Teknekron found that the 24-hour secondary TSP standard was exceeded 32 times, and the 24-hour sulfate standard six times, during the equivalent of a six-month period. Long-range-transport conditions, predominantly from the south and southwest, were either confirmed or deemed probable for 63 percent of these occasions. Furthermore, for six days when the TSP concentration was at least $150 \mu\text{g}/\text{m}^3$ and long-range-transport conditions occurred, the sulfate value (attributable to outside sources) provided the additional increment needed to push the TSP measurement over the secondary standard.

The DER data for Erie showed fewer standard violations but many days on which the sulfate-to-TSP ratio was significant. As for the Monongahela Valley, long-range-transport conditions were confirmed for 38 percent of the days on which the secondary 24-hour TSP standard was exceeded and for 33 percent of the days in which the sulfate standard was exceeded during the equivalent of about a one-year period. On all the dates of exceeded standards, 46 percent of the extremely persistent winds came from the southwest, 39 percent from the west, and 15 percent from the south. Correlative analyses with long-range-transport conditions at both Erie and the Monongahela Valley were hampered by the lack of concurrent meteorological data, but this shortcoming will be rectified in Teknekron's final report to the EPA.

Teknekron's ongoing work is directed at obtaining and analyzing additional information to uncover more cases of degraded air quality associated with long-range-transport conditions and to establish greater geographic coverage of Pennsylvania's western, southern, and northern border regions. The ultimate aim of ongoing work is to quantify the relative contributions made by specific sources to Pennsylvania's sulfur dioxide, TSP, and sulfate levels,

in order to substantiate any judgement regarding modifications to Ohio's SIP, and the proposed relaxation of emission limits for the West Virginia power plants. To this end, improvements are needed--and are being pursued--in the quantity of meteorological data and validation cases, the quality of emissions data, and the sophistication of transformation-chemistry modelling.

EPRI's Sulfate Regional Experiment (SURE) (E-6)

The second important research program we mention here is EPRI's Sulfate Regional Experiment (SURE). This 3-year, \$6-million program is intended to study the relationship between emitted primary pollutants and regional ambient concentrations of secondary products. Emphasis is upon SO₂ emissions from power plants in the northeast, where the sulfate concentrations are the highest. EPRI, the research arm of the electric utilities, is especially interested in determining the extent to which utilities will have to reduce emissions of SO₂ in order to meet an ambient sulfate standard, and in avoiding the imposition of SO₂ controls where utilities do not in fact need them in order to meet a sulfate standard. Recognizing that the relationship between product sulfates and precursor SO₂ is not simple, EPRI seeks to learn more about this relationship and thus to develop a sound basis for limiting emissions of SO₂ as a precursor of sulfates, perhaps as a function of geographic and aerometric conditions.

Background work for the SURE program included an evaluation of whether the sulfate problem is a regional one, as had been suspected. Findings included: (1) Local ambient sulfate levels correlate poorly with local and subregional SO₂ levels. (2) Long-term averages of subregional sulfate concentrations show irregular geographical distribution patterns. (3) Sulfate concentrations seem to correlate with both temperature and dew point. (F-6) The SURE program involves an extensive ground level measurement network; aircraft measurements of vertical pollutant profiles in the neighborhood of a ground station; a detailed emissions data base; and simulation modeling of SO₂-sulfate conversions, which will use the pollutant and emissions inventories for testing and verifying models.

Figure F-4 shows the SURE stations. The crosses represent class 1 stations, which will measure a large variety of pollutants year-round. The circles represent class 2 stations, which are part of the regular utility network. These will make additional measurements during "intensives", which will take place four times a year. Three-hour sulfate measurements will be made during intensives, while 24-hour sulfate measurements will be made otherwise.

EPRI has incorporated a number of EPA monitoring stations into its network. Additionally, a special EPA sampler developed by Florida State University--permitting 2-hour measurements of sulfate--has been installed.

The SURE measurements have permitted correlations between wind persistence and elevated sulfate levels at various locations. Examples of such correlations are presented in Table F-2 for several locations at which significant episodic increases of sulfate levels have been associated with wind transport of SO_2 and sulfates. In this table the number of days of extreme wind persistence during a period of measurement (generally about one year) is related to three ranges of observed sulfate concentrations.

The SURE data developed so far have been used in a number of studies of sulfate episodes. (F-3, F-7)

The Midwest Interstate Sulfur Transformation and Transport Program

The third and last major program dealing with the generation and transport of sulfates is the interorganizational MISTT program coordinated by EPA, which tracks and analyzes power-plant and urban plumes, and also stagnating anti-cyclones (stagnant air masses in which transformations occur).

Airplane measurements have been used for three-dimensional mapping of air masses, allowing the measurement of chemical and meteorological parameters that can be used in attempts to model the transformation processes. The types and techniques of measurement used so far include:

- The use of mass flow measurements in addition to SO_2 -sulfate measurements, permitting a determination of the loss of SO_2 by ground deposition

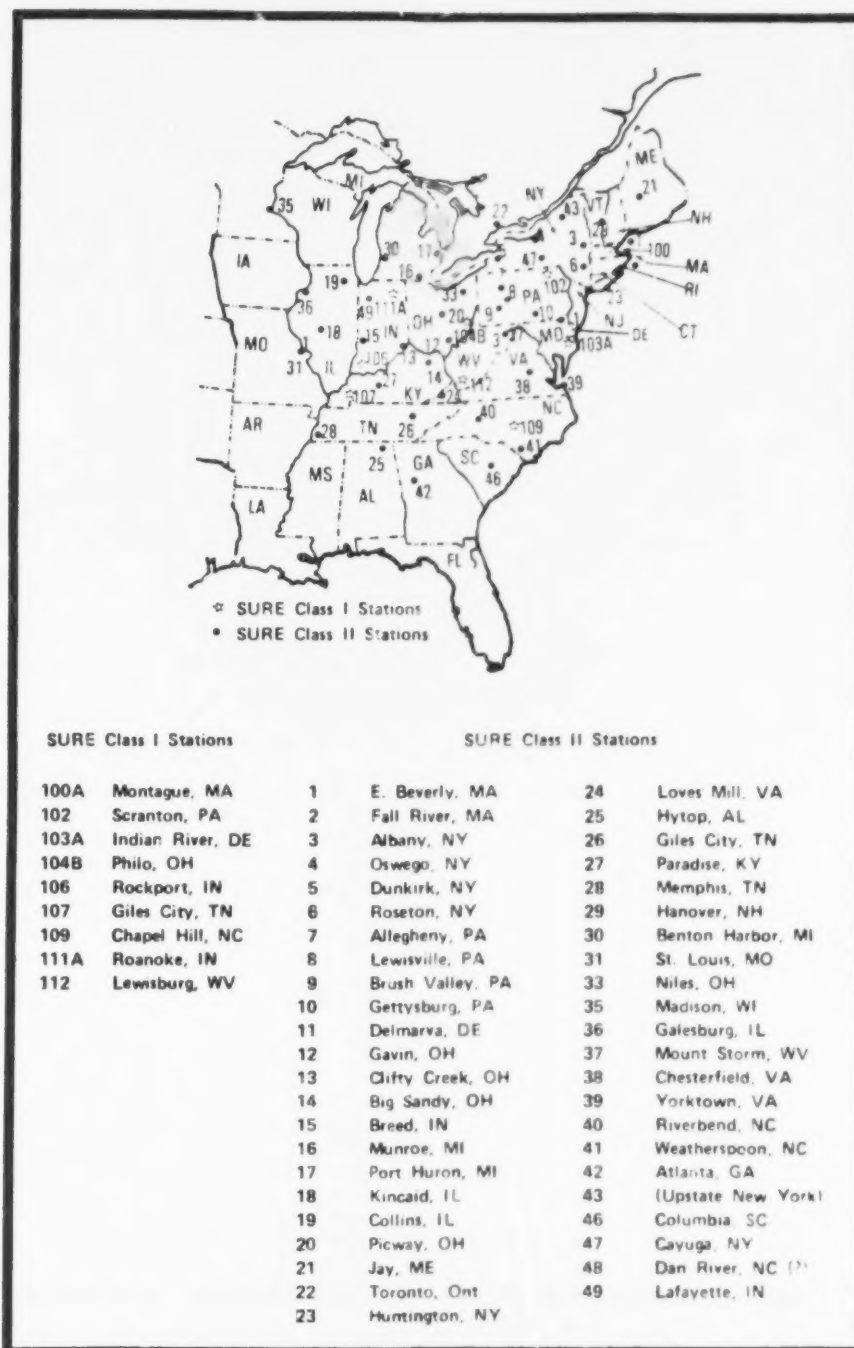


FIGURE F-4. SULFATE REGIONAL EXPERIMENT GROUND STATIONS (F-6)

TABLE F-2. TOTAL DAYS OF EXTREME WIND PERSISTENCE
ASSOCIATED WITH SULFATE DATA*

Location	Periods of Recording Meteorological Data	Daily Sulfate Concentrations ($\mu\text{g}/\text{m}^3$)		
		0-8.9	9.0-14.9	≥ 15
Albany, NY	6/13/74 to 3/30/75	73	31	13
Scranton, PA	4/10/74 to 3/30/75	87	15	5
Wheeling, WV	5/22/74 to 3/31/75	97	43	10
Huntington, WV	4/19/74 to 3/31/75	95	24	7
Lawrence, IN	4/4/74 to 3/31/75	149	20	6
Madison, IN	5/16/74 to 3/31/75	97	34	8

* Notes:

1. Information here is assembled from materials in Reference F-9.
2. A wind is defined as extremely persistent when, for six or more consecutive hours, its direction remains within a 45° sector, its speed remains within a specified range, and its stability class remains unchanged.

- Monitoring of the gaseous pollutants O_3 , NO, NO_x , and SO_2 ; three aerosol parameters, including sulfate; and several meteorological and navigational parameters
- Consideration of the time history of the air masses being studied, in addition to the three space dimensions
- Sampling power plant and urban plumes to within 300 km from their sources
- Tracking hazy air masses associated with stagnating anticyclones over 1000 km
- Measuring relative humidity, ozone levels, the extent of mixing of the plume with background air, background pollution levels in general, and particularly the presence of catalytic species on particulates
- Continuous sulfate measurements using continuous tracer measurements
- The use of Lidar to make nighttime plume measurements (which has not lead to conclusive information)
- Measurements of aerosol size distribution

Results of MISTT measurements to date include:

- Most daytime SO_2 -sulfate conversions were found to result from homogeneous reactions
- Daytime SO_2 -sulfate conversion rates in power plant plumes ranged from 0.5 to 5 percent per hour
- The amount of sunlight, the concentration of water vapor, and the concentration of ozone were important factors increasing SO_2 -sulfate conversion rates
- Aerosol volume flow rates (calculated from measurements of aerosol size distribution) were different depending upon the time of day and the distance from the source.

MISTT measurements in plumes from the Labadie power plant near St. Louis, Missouri, indicated a noontime SO_2 -sulfate conversion rate of 1-4 percent per hour, and nighttime rates below 0.5 percent per hour. Removal of SO_2 by dry deposition was also greater during the day, when there was considerable vertical mixing of air layers. At night the plume moved fast--more than twice as fast as the daytime plume--and with little change in the quantities of SO_2 and sulfate.

As a result of the MISTT observations that sulfate, generated from SO_2 in power plant and urban plumes, and ozone, generated from hydrocarbons and nitrogen oxides in urban plumes, may be transported at least hundreds of kilometers and cause air pollution far from the source, MISTT investigators point out the following policy implications:

"Air pollution resulting from long-range transport of secondary pollutants cannot be controlled by the political entity where the air pollution impact actually occurs. Therefore, our current concept of an air quality control region must be changed in order to take account of the long-range transport of secondary air pollutants."(F-8)

The future work in the MISTT program will be aimed at understanding heterogeneous reactions (believed to predominate during high relative humidity, at night, and in clouds), the dynamics of blobs (hazy air masses associated with a stagnating anticyclone); and obtaining more statistical information on conversion rates and mechanisms, and plume behavior. Additionally, future MISTT work is expected to include the study of gaseous and particulate nitrates and organic material, along with further measurements of sulfates and ozone.

The Tennessee Valley Authority (TVA) has been studying the transport and transformation of sulfur oxides in the Tennessee Valley region. While not part of the MISTT program, the TVA program involves plume studies similar to those being made in MISTT; both programs are under the same EPA coordinator.

The ongoing TVA program studies ambient air and stack gases in order to increase the understanding of the photochemistry of power plant plumes. Additionally box budget studies--involving observations of changes in SO_2 and sulfate across the Tennessee Valley--are being performed. One set of these studies, performed during the winter, indicated a 25 percent increase in sulfate as the air mass crossed the TVA region.

Beside the atmospheric studies, the TVA program is conducting simulative laboratory studies: studies are made of photochemical reactions in a stack-gas smog chamber containing material fed directly from a large power plant.

Implications of Transformation - Transport Studies for Modified SO_2 Emission Limitations

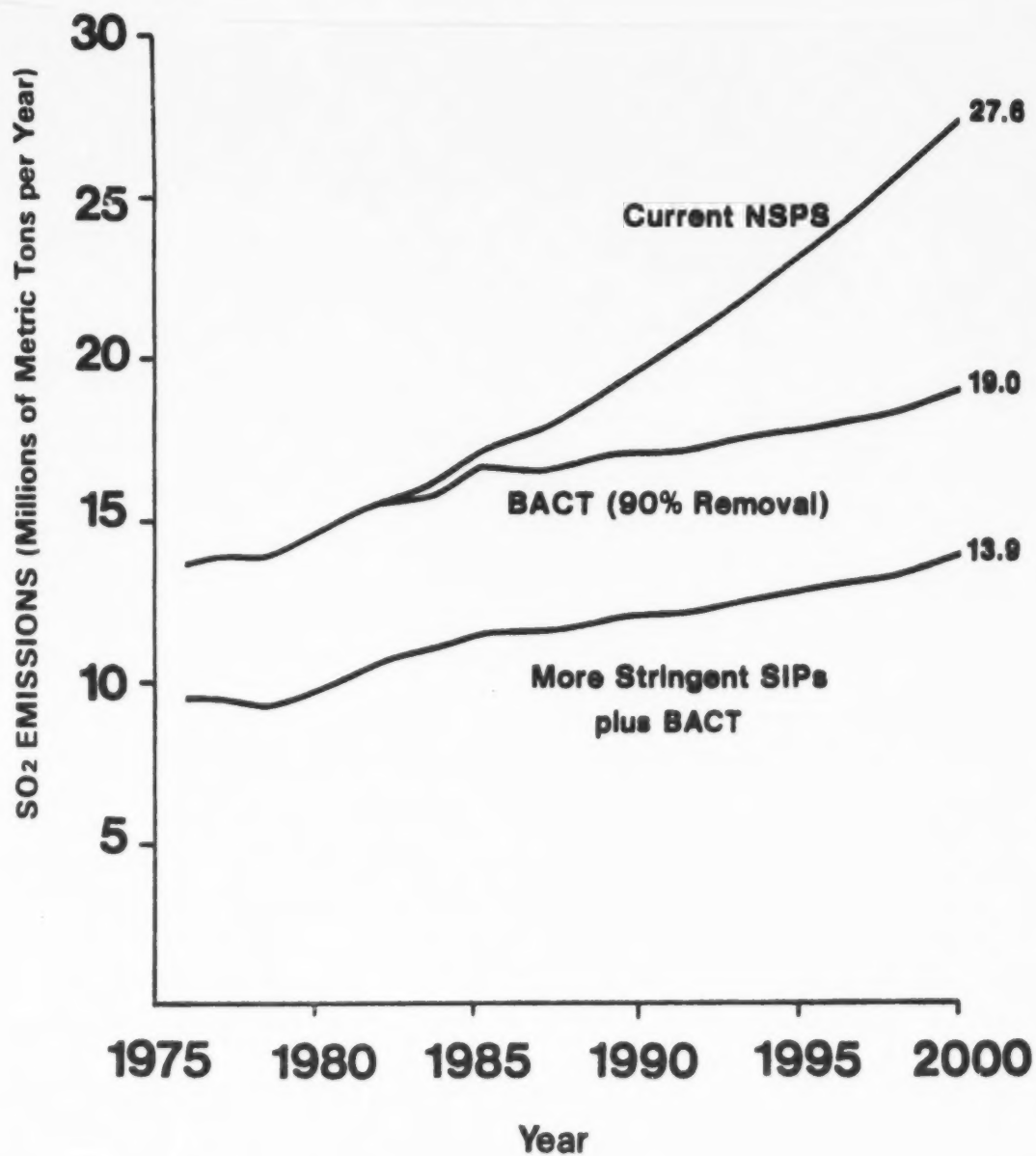
The results obtained so far, attributing elevated levels of sulfates and therefore TSP, and SO_2 to remote upwind sources, suggest guidelines for

the siting of new plants in order to avoid producing or receiving pollutants that are transported long distances. The results of available data and modeling are not, however, sufficiently quantitative to permit functional relationships that predict how much the emissions from existing plants, located on the transport trajectories, ought to be modified. Functional relationships would necessarily express the interdependence of meteorological factors, SO_2 to SO_4^{-2} conversion rates (which, in turn, depend upon topographical and meteorological conditions and the presence of other pollutants), the spatial distribution of pollutant sources, and the allowable increments of pollutant concentrations at receptor sites. Because wind persistence is intermittent (see Table F-2), and since other important parameters determining elevated downwind pollutant concentrations respond to effects that are intermittent, the need for the additional control of emissions at upwind sources in order to prevent long-range transport is, in fact, not necessarily continuous.

Continuous Supplemental Controls at Sources of Downwind Pollution

Nationally, electric utilities--which generate 72.5 percent of the SO_2 produced by all stationary combustion sources^(F-10)--produce considerably more SO_2 from plants that are subject to SO_2 emission limitations set by SIP's than from plants subject to NSPS. Even by 1995, as much as 60 to 80 percent of utilities' SO_2 emissions will come from SIP-controlled plants (under current SIP's).^(F-11) According to the 1977 Amendments to the Clean Air Act, the states must submit revised SIP's involving more stringent emission limitations to EPA by 1 January 1979. Revisions must include provisions for the use of "reasonably available control technology", and also--when needed to avoid impairment of visibility in a protected area--"best available retrofit technology".

To determine the effect of more stringent SIP limitations on SO_2 emissions from utility boilers, Teknekron's Utility Simulation Model (USM) was applied using alternative specifications for (1) more stringent SIP's, and (2) growth in electrical demand. Figures F-5 and F-6 show how effective revised SIP's can be in decreasing SO_2 emissions nationally. Figure F-5 displays SO_2



* Assumed growth in electrical demand: 5.8% per year until 1985, 5.5% per year afterwards.

FIGURE F-5. NATIONAL POWER-PLANT SO₂ EMISSIONS UNDER ALTERNATIVE CONTROL SCENARIOS, HIGH GROWTH

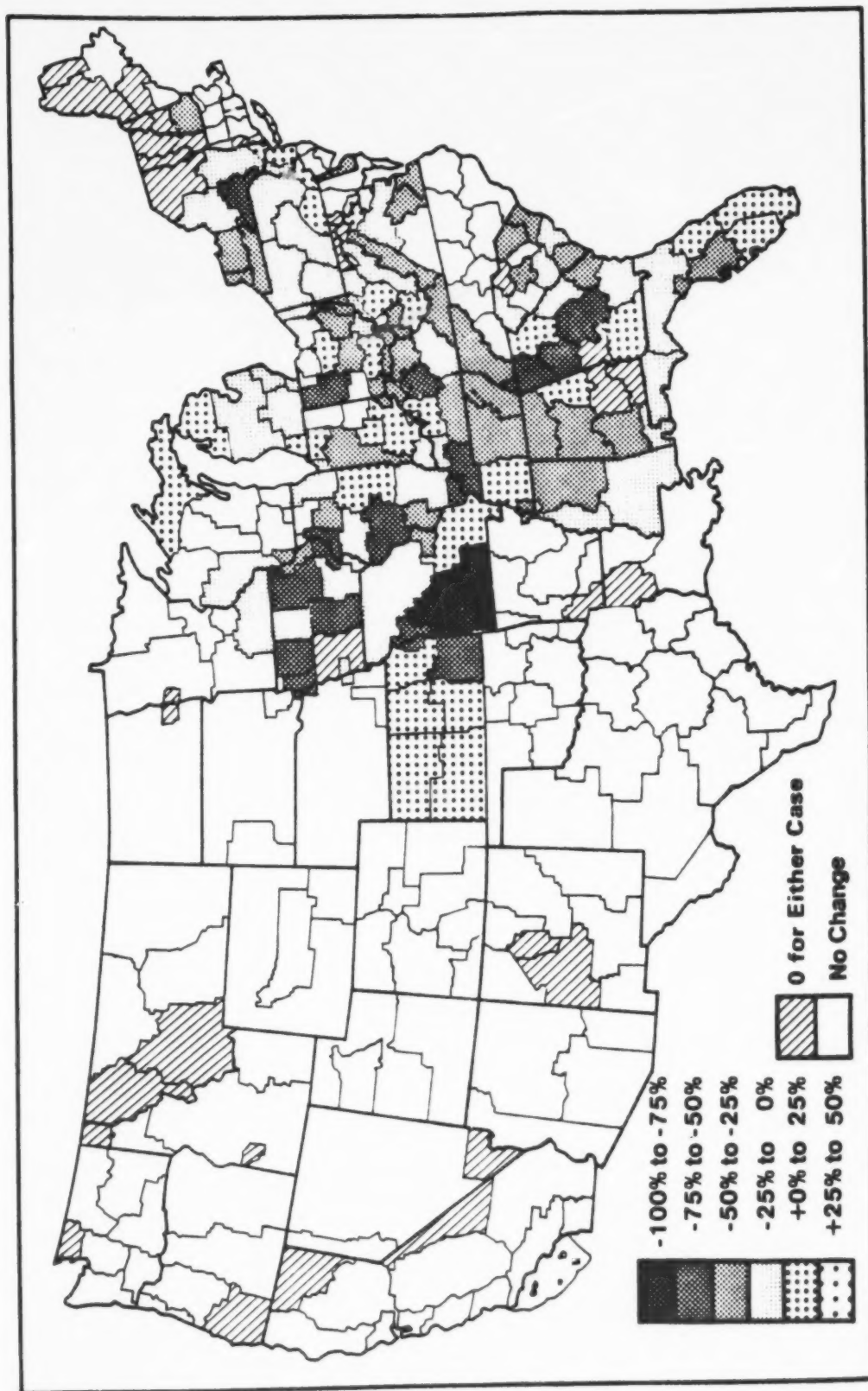


FIGURE F-6. PERCENTAGE CHANGE IN SO₂ EMISSIONS IN 2000
(BACT WITH MORE STRINGENT SIP'S)

emissions from electric utilities as a function of time, assuming a national annual electricity demand growth rate of 5.8 percent before 1985 and 5.5 percent after 1985. The curves labeled "BACT" in Figure F-5 represent a likely revision to the NSPS for SO₂: 90 percent reduction of potential SO₂ emissions from uncleaned coal, and an upper bound of 1.2 lb SO₂/10⁶ Btu. The curve labeled "More Stringent SIP's" represents a modification of the current SIP's: whenever current SO₂ limitations exceed 2.0 lb SO₂/10⁶ Btu they were reduced to 2.0 lb SO₂/10⁶ Btu. As may be seen from Figure F-5, a comparison of national SO₂ emissions using BACT but two different sets of SIP's shows that SO₂ emissions are considerably lower when the more stringent SIP's are applied.

Figure F-6 illustrates that the benefit of more stringent SIP's would predominate in the eastern U.S. Since current SIP's in western states--where ambient SO₂ concentrations are generally much lower than those in the east--already specify that SO₂ emissions be less than 2.0 lb SO₂/10⁶ Btu, the assumed revisions to SIP's do not affect the western states.

The revised SIP's for SO₂ discussed above limit pollutant emissions on a continuous basis. In the following section, we consider the application of intermittent SO₂ controls to supplement continuous SO₂ controls. These supplemental intermittent controls would restrict SO₂ emissions at sources that, according to air quality studies, cause significant but intermittent incremental concentrations of SO₂ and sulfates at long range.

Intermittent Supplemental Controls at Sources of Downwind Pollution

Let us suppose for the present discussion that the results of the ongoing research on atmospheric transport of pollutants could, in fact, establish reliable (and necessarily complex) predictive methods for determining when additional intermittent controls are needed at upwind pollutant sources. Would intermittent control systems (ICS), that is, time-variable air pollutant emission control strategies, be permissible according to legislative and regulatory policy?

The Clean Air Act of 1970 raised the question of whether intermittent controls were an acceptable alternative to continuous emission controls. EPA's answer was "no", backed by judicial rulings. The 1977 Amendments to the Clean Air Act have codified EPA's position: the Act now states that emission limitations specified in SIP's must be continuous, so that dispersion techniques, such as tall stacks, and other ICS, such as intermittent use of low-sulfur coal, cannot be used to meet emission limitations. (F-12)

ICS have been of interest to pollutant emitters largely because, under certain meteorological conditions, a downdraft occurs, causing appreciably increased concentrations of SO_2 near the ground in the vicinity of the emission source. The use of an ICS would prevent these intermittent incidents of elevated SO_2 levels near the source. One class of ICS (Class I) uses a predictive meteorological model to signal the need for lowering emissions. The TVA system has used such a model, and can shift from high sulfur to low sulfur coal (perhaps PCC) in one-half hour. A second class of ICS systems (Class II) uses feedback information about SO_2 levels in addition to meteorological forecasting, sometimes with considerable success in reducing the incidence of violations of air-quality standards. (F-13) Industries not requiring a constant rate of output could use these monitoring systems to reduce their output when necessary.

Although "emission limitations" contained in SIP's must, according to the definition in the 1977 Amendments, limit pollutant emissions on a continuous basis, it appears that the Clean Air Act may have left open the question of whether some degree of intermittent controls may be permissible at stationary sources causing long-range downwind pollution episodes. The intermittent controls applied at these sources would supplement controls for meeting continuous limits required by the NSPS or SIP's (which are designed to ensure maintenance of local air-quality standards) in order to reduce the impact of these sources on air quality at long range. As may be seen in Table F-3, which presents examples of sectors of extremely persistent winds, the maximum duration of wind persistence is about 12 hours. If intermittent controls for the purposes described here do not, in fact, conflict with environmental policy, any results that may emerge from transformation-transport research programs, establishing time-dependent, source-receptor relationships, and means of forecasting periods of significant incremental downwind pollution, could be used to signal the use

TABLE F-3. EXAMPLES OF SECTORS OF EXTREMELY PERSISTENT WINDS

Station	Stability Classes	Persistence (hours)	Most Frequent Direction	Average Number of Cases per Year	Average Number of Cases in Summer and Fall	Average Wind Speed (m/sec)	Transport Distance (km)
Ohio (Continued)							
Toledo 2/55-12/64	B-E	6	SW	46.2	14.8	4.1-10.2	155
		6	S	22.6	6.5	4.1-10.2	155
		6	W	16.1	--	4.1-10.2	155
		6	NE	14.0	--	4.1-10.2	155
		6	N	9.2	--	4.1-10.2	155
		6	NW	11.4	--	4.1-10.2	155
		6	SE	3.0	--	4.1-10.2	155
		6	E	5.7	--	4.1-10.2	155
		12	SW	10.6	1.8	4.1-10.2	311
	12	W	1.8	0.9	4.1-10.2	311	
Youngstown 1/55-12/64	B-E	6	SW	51.3	17.3	4.1-10.2	155
		6	S	25.7	12.0	4.1-10.2	155
		6	W	20.8	5.8	4.1-10.2	155
		6	NW	16.6	--	4.1-10.2	155
		6	SE	13.5	--	4.1-10.2	155
		6	N	11.8	--	4.1-10.2	155
		6	E	6.3	--	4.1-10.2	155
		6	E	4.3	--	4.1-10.2	155
		12	SW	13.4	3.7	4.1-10.2	311
	12	S	5.4	2.8	4.1-10.2	311	
Zanesville 12/48-12/54	B-E	6	W	22.5	3.6	4.1-10.2	155
		6	S	19.9	7.2	4.1-10.2	155
		6	SW	18.1	5.3	4.1-10.2	155
		6	SE	12.5	--	4.1-10.2	155
		6	NW	9.4	--	4.1-10.2	155
		6	N	3.1	--	4.1-10.2	155
		6	NE	1.5	--	4.1-10.2	155
		6	E	0.5	--	4.1-10.2	155
		12	S	4.4	1.2	4.1-10.2	310
	12	W	3.6	0.7	4.1-10.2	310	
Oklahoma							
Oklahoma City 1/55-12/64	B-E	6	S	65.7	31.0	4.1-10.2	155
		6	SE	68.1	23.8	4.1-10.2	155
		12	SE	26.7	8.4	4.1-10.2	311
		12	S	23.9	3.6	4.1-10.2	311
Pennsylvania							
Allentown 1/55-12/64	B-E	6					
		6					
		12					
		12					
Erie 1/55-12/64	B-E	6	S	40.2	19.2	4.1-10.2	155
		6	SW	27.8	7.5	4.1-10.2	155
		6	W	24.5	7.7	4.1-10.2	155
		6	SE	24.4	--	4.1-10.2	155
		6	NE	14.0	--	4.1-10.2	155
		6	N	12.8	--	4.1-10.2	155
		6	NW	12.0	--	4.1-10.2	155
		6	E	0.6	--	4.1-10.2	155
		12	S	9.6	4.6	4.1-10.2	311
	12	SW	0.7	0.3	4.1-10.2	311	

Note: One knot = 0.51 m/sec.

of intermittent controls at the source (during periods which may not be concurrent with those of the related downwind pollution episodes). Additional controls imposed only when needed to prevent long-range pollutant transport might generally be more economical--on a financial, and, to some extent, an energy basis--than would additional controls that operate on a continuous basis.

Summary

Ongoing research indicates that existing sources are responsible for violations of air-quality standards at long range. Should this research result in the development of source-receptor relationships that can be used to identify sources of long-range air quality impacts, it is likely that pressure will develop to set more stringent SO₂ emission limitations for these sources. The extent to which allowable SO₂ limitations would be decreased will probably be determined by a combination of area-specific empirical testing and quantitative reliable source-receptor models--if research programs succeed in verifying such models for specific geographic areas. The required additional controls, which would include the substitution of lower sulfur coals (perhaps PCC), could conceivably operate either continuously or intermittently, in order to prevent long-range pollutant transport and transformation.

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APPENDIX G

BARRIERS TO EXPANDED USE OF COAL CLEANING

APPENDIX G

BARRIERS TO EXPANDED USE OF COAL CLEANING

A number of barriers exist which may impede the continued development and deployment of physical coal cleaning as a sulfur dioxide control strategy. These barriers fall into several categories: technical, environmental, transportation, institutional, economic and social, and regulatory and legislative.* The nature of the constraints in each of these categories is discussed in the following paragraphs.

Technical Barriers

Introduction

Physical cleaning of coal has been practiced for many years in the United States with the basic motives being related to market and financial considerations. Its principal purpose has been traditionally to reduce the ash-forming impurities, raise heating values, and lower transportation costs. Recent emphasis on environmental considerations, however, has given impetus to the adaptation of physical coal cleaning for the removal of sulfur. The inherent limitation with physical cleaning is, of course, that it only removes the pyritic sulfur in the coal.

Since the specific gravity of pyrite is three to four times higher than that of coal, all the pyritic sulfur theoretically can be separated from coal by gravity separation methods. In practice, however, there appear to be two major problems in removal of pyritic sulfur from coal. First, because pyrite in many coals is finely disseminated in the coal matrix, very fine grinding is necessary to accomplish the separation. In general, however, the gravity separation methods are effective for relatively coarse-size particles. Secondly, coal and pyrite appear to have similar surface characteristics, which complicate

* Contributions by Teknekron to the sections on institutional, economic and social, and regulatory and legislative barriers were used in the preparation of this appendix.

separations based on this property. Consequently, current physical coal cleaning removes only about 50 percent of pyrite sulfur present in coal.

Despite its limited capability of sulfur removal, physical coal cleaning can be used on a limited number of U.S. coals with a favorable pyritic/organic sulfur composition to meet federal new source performance standards for steam generators. Moreover, even if physical coal cleaning alone cannot remove enough sulfur to meet the SO_2 emission standards, it can be used advantageously in conjunction with flue gas desulfurization or with fluidized-bed combustion to lower the SO_2 emission control costs.

Technical barriers to the wide implementation of physical coal cleaning as a sulfur control strategy can be divided into three major areas:

- The lack of techniques for accurate prediction of the cleanability of raw coals
- The lack of techniques for quality control of the clean coal product of consistent sulfur content
- The lack of techniques for effective liberation and rejection of fine-size pyrite.

These technical barriers must be overcome before physical coal cleaning can be extensively used as a method of SO_2 emission control.

Prediction of Coal Cleanability

The projection of anticipated cleaning results is a prerequisite step for taking economical risk in mining new coal reserves and building new coal cleaning plants. The enhancement of coal quality which could be brought about by physical cleaning depends upon such factors as coal seams, density composition, size composition, forms of sulfur present, cleaning equipment, separating density, etc.

Traditionally, washability tests are being conducted to determine how well a given coal can be cleaned at a given specific gravity of separation. The test involves stage crushing and float-sink separation in heavy organic liquids of several different specific gravities. Recently, the U.S. Bureau of Mines^{(G-1)*} compiled washability data on 455 U.S. coal samples with special emphasis on sulfur reduction potential. It shows what effects top size reduction and specific gravity fractionation have on the liberation and subsequent removal

* References for Appendix G are given on page 410.

of pyritic sulfur. Their work, however, is principally on coals available from existing mines. This information needs to be extended to coal seams and geographic areas not currently developed. The current washability data base is for coals with top sizes from 1-1/2 inches to 14 mesh. Liberation and physical desulfurization studies should be done on various coal seams with a view to determine the sulfur reduction potential at finer coal sizes.

The laboratory washability data represent the ideal separation, where all of the coal lighter than the density of separation reported to the product coal, and all of the material heavier than this density reported to the refuse. This ideal separation, however, is never realized in commercial coal cleaning practice. In order to predict results of commercial coal cleaning, the performance of individual equipment used in the process must be evaluated by washing coal of about the same characteristics as the one for which the prediction is being made. Although the performance characteristics of various types of coal cleaning equipment have been investigated by the Bureau of Mines^(G-2 - G-12), some data must still be obtained for certain types of equipment, particularly at fine coal sizes-

The prediction of cleaning results attained in commercial coal cleaning further is complicated by a large number of possible operational variables such as specific gravity of separation, viscosity, slurry concentration, load factor, coal size distribution, chemical reagents, etc. Recently, computer models have been developed to simulate the performance of coal cleaning plants.^(G-13, G-14) However, much more work is needed to develop a fully functional computer simulation which can be used for prediction or optimization of the desulfurization potential of commercial coal cleaning plants.

Quality Control of Coal Cleaning Process

Another major problem in implementing coal cleaning as a sulfur control strategy is difficulty in controlling the quality of the product to provide a consistent sulfur content. For power plant usage, uniformity of coal quality is perhaps

the most important single attribute contributing to economical boiler operation. In particular, the exact amount of sulfur in coal must be known in order to utilize coal in an environmentally acceptable manner. The continuous variations in feed coal properties make it extremely difficult to produce uniform quality coal from physical coal cleaning plants. However, cleaned coal has more uniform properties than raw coal.

In the past, coal cleaning processes were controlled manually by the operator with a minimum of process instruments. Today the tendency is to design a new plant to operate in a fully automatic manner in order to maximize the efficiency of labor utilization. There are numerous types of automatic equipment available for use in the coal industry.^(G-15) For example, equipment has been developed to analyze coal continuously for its ash and moisture content by using nuclear radiation or x rays. There are a number of resistance and induction-type furnaces which can be used to determine the sulfur content of coal in a matter of minutes. More recently, a new type of sulfur monitoring system,^(G-15) using a nuclear source to determine rapidly the amount of sulfur in coal, has been developed. However, process control techniques which could be used to adjust plant operating conditions in response to the changes in the sulfur content of feed coal are not yet commercially available. An alternative scheme for quality control would be the development of automatic blending techniques to minimize the sulfur variation in the feed coal or cleaned coal.

Separation of Fine Size Pyrite

Another technical barrier which prevents the more extensive utilization of physical coal cleaning as SO_2 emission control is the lack of techniques for the complete liberation and rejection of fine-size pyrite. The extent of sulfur removal by physical cleaning depends primarily upon the size and distribution of pyrite grains within the coal. In some cases, where the pyrite exists as large relatively discrete crystals, a high degree of rejection is easily obtained. On the other hand, if the pyrite consists of small grains mixed intimately through the coal matrix, separation by physical cleaning can be extremely difficult.

The U.S. Bureau of Mines report on the washability of U.S. coals^(G-1) indicates that, in general, finer grinding results in greater sulfur rejection

or higher yield. It implies that if coal is ground and processed at finer particle sizes than practiced in current coal cleaning, much higher sulfur removal could be obtained. Unfortunately, however, the separation efficiency of commercial equipment becomes poorer as the particle size decreases, and current separation techniques are impractical for particle sizes below 50 micrometers. In order to expand the sulfur removal capacity of physical coal cleaning, practical methods are needed for liberating the pyrite without fine grinding and for separating the pyrite once it has been liberated.

Present techniques of liberation are mechanical crushing and grinding, where the lump coal is ground to small sizes until a large portion of impurities becomes detached from coal. Hence, very fine grinding is necessary to liberate finely disseminated pyrite. Development of comminution methods which selectively liberate pyrite from coal at the largest possible size would greatly improve physical coal cleaning. Recently, chemical comminution of coal using ammonia has shown its potential to improve pyrite liberation without mechanically grinding to a fine size.^(G-17)

Thus far, froth flotation continues to be the only commercial process for treating fine-size coal. However, it is not particularly suited to sulfur reduction because coal and pyrite appear to have similar surface characteristics. A number of new techniques for physical coal cleaning are being investigated to improve the pyritic sulfur removal from fine-size coal. Among the more promising techniques are two-stage froth flotation,^(G-18) selective oil agglomeration,^(G-19) and high gradient magnetic separation^(G-20). However, these processes are still in the experimental stage and need much more work before full-scale commercial application can be achieved.

Conclusion

In order to implement physical coal cleaning as a sulfur control strategy, additional research, development, and demonstration activities are needed in the following areas:

1. Accurate prediction of coal cleanability:
 - Washability data for new coal reserves and at finer coal sizes
 - Performance data of commercial equipment
 - Correlation between laboratory washability data and commercial coal cleaning results

- Computer simulation of coal cleaning plants.
2. Quality control of coal cleaning process:
 - On-line instrumentation to give immediate sulfur contents
 - Automatic control to adjust process variables such as medium density, viscosity, or feed rate
 - Automatic blending to give uniform quality coal.
 3. Separation techniques of fine-size pyrite:
 - Selective comminution of coal to enhance removal of pyrite
 - Effective separation of fine-size coal
 - Dewatering and drying of fine-size coal
 - Handling and transportation of fine-size coal.

Environmental Barriers

The commercialization of physical coal cleaning for SO₂ emission control has been retarded by several types of barriers, such as technical, economic, institutional, and social. One type of barrier that is frequently overlooked, however, is environmental barriers. For example, the waste materials generated from coal preparation can themselves be important sources of environmental contamination. Furthermore, although environmental control is technically feasible for most of these wastes, frequently the control devices or techniques themselves present new pollution problems.

This section will assess particular environmental problems which may act as barriers to the use of physical coal cleaning as an SO₂ emission control.*

Land Use Impacts

In terms of environmental consequences, the land use impacts associated with coal cleaning operations are often very significant. Land-related impacts tend to be much more noticeable visually than those involving air, water, or noise, and may have direct economic and aesthetic impacts for residents of nearby communities. (G-21)

* The reader is referred to Appendix E for a general discussion on environmental pollution from physical coal cleaning.

Coal cleaning complexes tend to be large in terms of total land area required when compared with other economic activities. For example, a coal cleaning facility with ancillary services such as storage, transportation, waste disposal areas, and ponds may range from 40 to more than 500 acres. Allowing for an employment range of 20 to 50 persons, this means that these activities may require between two and ten acres per employee.^(G-22) On the other hand, the typical manufacturing plant in the United States employs 80 to 100 persons and utilizes four to six acres of land, resulting in a requirement of approximately 0.05 acre per employee.^(G-21)

In terms of land use, the coal cleaning operation precludes the use of the site and the immediate surrounding area from any use except heavy industrial, transportation, or other mineral-processing activities. In addition, the complex may require substantial modification of local topographical features. For example, the leveling of open-storage areas and hard stands for various types of equipment, as well as the creation of ponds and lagoons may necessitate substantial earth removal and subsequent deposition in spoil areas. Moreover, the creation of surface and valley waste disposal areas and the construction of major dams and embankments may involve significant modifications of natural terrain features.^(G-21,G-23)

Depending upon the size of the preparation plant, its age, and the nature of the coal being treated, solid waste disposal areas may be the largest users of land related to coal cleaning. For example, the coal refuse disposal area for the preparation plant at Homer City, Pennsylvania, consists of 180 acres. This area is intended to accept one million tons of refuse per year and will be in use for 30 years.^(G-23) Sites such as these require extensive grading, the creation of barriers and buffers, and extensive engineering preparation and compaction.^(G-21)

A number of aesthetic impacts may result from the operation of a coal cleaning complex. The silos, conveyers, towers, and other components of the facility are large, may have considerable vertical dimension, and may be readily observable from beyond the confines of the total complex. In addition, piles of untreated coal, treated coal, and waste may have a negative visual impact when viewed from surrounding areas.^(G-21)

The construction, operation, and related activities of a coal cleaning plant may also have a number of economic impacts on both the site of the

complex itself, and in surrounding areas. For example, the noise, coal dust, and contaminated water, as well as aesthetic characteristics of the preparation plant, may be major factors in discouraging residential, commercial, industrial, and recreational development on surrounding lands. Furthermore, when communities exist in close proximity to the preparation plant, the economic viability and further development of the community may be adversely affected. (G-21)

Solid Waste Disposal

The disposal of coal cleaning plant wastes is a worldwide problem of increasing magnitude. In 1974, coal production in the United States was nearly 590 million tons, exclusive of anthracite. Of this amount, approximately 49 percent, or 289 million tons, were cleaned by mechanical means. This resulted in an estimated 96 million tons of coal preparation refuse. (G-24) It is estimated that the coal waste piles and impoundments accumulated between 1930 and 1971 in the United States cover approximately 225,000 acres of land. (G-25)

Depending upon the degree of size reduction employed in the coal cleaning process, refuse may be generated coarse (+28 mesh) or fine (-28 mesh). Coarse refuse may be generated dry, or if generated in a wet process, drains fairly readily. Coarse refuse is usually disposed of in an embankment or landfill. Fine refuse is generated by wet processes and is generally removed from the preparation plant as a thickener underflow and impounded into nearby settling ponds. In many cases, the settling pond is impounded by a coarse refuse embankment. (G-21, G-23)

Since the 1972 Buffalo Creek disaster at Saunders, West Virginia, when a coal waste embankment failed, causing heavy losses in lives and property, greater emphasis has been placed on the stability of coal waste embankments. In addition to periodical inspections conducted by coal mine inspectors, large-scale engineering evaluation of the more significant and potentially hazardous water-impounding coal waste embankments has been conducted by the Mining Enforcements and Safety Administration. (G-26) The U.S. Bureau of Mines investigated the physical properties of coal refuse with regard to structural stability. (G-27, G-28) Engineering considerations on the construction of coal waste embankments have also been published.

Potential Pollution. Solid waste is the largest single source of potential pollution from coal preparation. The adverse effects associated with coal refuse disposal include air pollution, water pollution, land pollution, safety hazards, and ecological and psychological impacts. (G-21)

The weathering and leaching of coal refuse dumps produce several types of water pollution. These include silt, acids, and other dissolved mineral matter. It has been estimated that about 2000 coal waste dumps in the U.S. are contributing to stream or waterway pollution. (G-25) Water pollution from coal waste dumps is similar to that from surface mines; for example, wastewater from a refuse disposal area can continue indefinitely to pollute after the disposal has ceased, and the volume of wastewater is highly dependent on precipitation and surface water flow patterns. (G-23)

Siltation from coal refuse dumps is caused by finely divided coal, minerals, and discarded soil. Particularly in regions with mountainous terrain and very little space for retention or sediment ponds, suspended solids are a major problem. Though the problem is usually critical to the water quality only after a storm, the sediment has a lasting effect on the receiving stream because it sinks to the bottom and covers the feeding and breeding areas for aquatic life. (G-30)

Acid drainage is produced when iron sulfides are exposed to air and water. The sulfur is oxidized to sulfuric acid, and the iron is solubilized as iron sulfate. Typically, 1.5 to 2 pounds of acid and 0.5 to 0.7 pound of soluble iron are produced per acre of refuse surface per day; however, in some highly mineralized areas, acid has formed at a rate of more than 300 pounds per acre per day. (G-25) The acids formed run off into drainage ditches or percolate through the pile, where considerable mineral matter may be dissolved. (G-23)

Another potential class of pollutants from coal refuse is trace or minor elements. These materials can be subjected to leaching by rainwater or surface flows and result in water pollution problems. In addition, under certain conditions, burning refuse piles could discharge some of these elements into the atmosphere (G-23) (see Trace Elements and Control, page 169).

Control Methods. The best overall practice of environmental control for coal refuse disposal areas is proper construction and maintenance. Present control methods include compaction, grading, sealing, and collection and treatment (see Solid Waste Pollution and Control, page 164).

Reclamation of Waste Disposal Areas. The most positive approach to preventing pollution from disposal areas is probably reclamation. Refuse piles are very similar to spoil banks, as far as morphology is concerned, and reclamation of refuse piles can be achieved through procedures similar to those practiced for the reclamation of the mine spill banks.^(G-32) Reclamation procedures can be divided into the following sequential steps: contouring, soil stabilization, soil conditioning, revegetation, and reclamation for alternative uses.^(G-23)

Waste Utilization. Because the potential pollution problems associated with refuse disposal are so great and because coal refuse offers significant combustion heat content and other mineral values, serious consideration is being given to its utilization as a raw material. Presently, the coal industry and government are developing new uses and reexamining earlier uses for coal refuse.^(G-23)

The results of a laboratory testing program^(G-33) indicate that the engineering properties of coal refuse are only slightly different than would be expected for typical soils. In addition, there are no adverse engineering properties associated with coal refuse which would prevent its use as a construction material.^(G-34) Coal refuse has been successfully used as a road base material, a building material, and a fill material for construction purposes. Other uses include elemental sulfur production, metal extraction, and heat generation.^(G-23)

Trace Elements

Trace elements differ in their susceptibility to removal from coal by density separation. This is generally considered to result from the fact that some compounds of trace elements are typically associated with the heavy mineral phases while other trace elements are associated with the coal itself. Thus, one can conclude from the reported data that significant amounts of elements will be discarded in the washing refuse and that this refuse will have a higher concentration of these elements than was present in the feed coal. This phenomenon is known as biogeochemical enrichment. Within the waste dump, both clay minerals and carbon residues are known to have considerable ion exchange capacity, and such processes as coprecipitation and selective dissolution can concentrate or deplete certain elements or compounds from solution.

In addition, many of the soils in the areas surrounding the waste disposal sites can accumulate toxic ions, presumably via an ion exchange mechanism. (G-31)

The preparation plant equipment is generally too large and feedstock too variable to determine easily what happens to trace elements during coal preparation. Thus, to simulate these processes on a laboratory scale, Ruch et al. (G-35) devised several float-sink tests which depict the behavior of the property measured as the density of the sample (washing medium) changes. Table G-1 shows the effect coal cleaning has on the distribution of elements between the clean coal and refuse portions. All of these elements except for B and Ge are more concentrated in the refuse. Be distributes almost evenly between the clean coal and the refuse. A similar study has been conducted by Schult, et al. (G-36) The distribution of eight elements after 1.6 specific gravity separation of coal from several coal beds is summarized in Table G-2. The results are similar to those shown in Table G-1 except for Cd.

From the above data it is seen that significant reductions in the trace-element content of coals are achieved by washing. Likewise, significant quantities of these elements will be discarded by the preparation plant. If these data are representative, then, the refuse will contain approximately 2.5 times the trace-element level present in the raw coal. (G-31)

Potential Pollutant. There seems to be little doubt that the run-off or drainage from coal waste disposal areas will be contaminated to some degree with dissolved or suspended mineral matter. Generally, the highest concentrations of contaminants are found in the more highly acidic effluents, although the run-off even from nonacidic wastes contains enough added material to be notable. Acid drainage from coal-processing refuse typically contains high concentrations of Fe, Al, Ca, Mg, and SO_4 ions. These are derived, apparently, from the major minerals in the wastes. However, little is known about the effects of weathering and leaching on the less abundant or minor elements in coal-processing wastes. Considering the high degree of mineral dissolution, many of the minor elements associated with the minerals in coals must also be present in the contaminated run-off from coal wastes. (G-31)

In 1974, Martin (G-30) sampled run-off from several coal refuse piles in Pennsylvania, West Virginia, Kentucky, and Indiana to provide data concerning the pollutants to be expected. This study is one of the most comprehensive

TABLE G-1. DISTRIBUTION OF ELEMENTS IN FLOAT-SINK SEPARATION OF ILLINOIS COALS AT VARYING SPECIFIC GRAVITY TO ACHIEVE 75 PERCENT WEIGHT RECOVERY^(G-35)

Element	Concentration (ppm unless otherwise stated)			Enrichment Factor	
	Raw Coal	Clean Coal	Refuse	Clean Coal	Refuse
Al	2.3 %	0.5 %	7.8 %	0.22	3.39
Ca	0.38%	0.07%	1.32%	0.19	3.47
Fe	2.9 %	0.80%	9.3 %	0.28	3.21
K	0.28%	0.09%	0.87%	0.32	3.11
Mg	81.2	34.5	215.1	0.42	2.65
Na	400.	200.	1000.	0.50	2.50
P	20.9	19.2	26.2	0.92	1.25
S	4.4 %	1.6 %	12.9 %	0.36	2.93
Si	4.2 %	0.9 %	14.2 %	0.21	3.38
Ti	1300.	450.	3900.	0.35	3.00
As	11.5	1.5	41.0	0.13	3.57
B	28.7	31.7	19.8	1.10	0.69
Be	3.0	2.9	3.3	0.97	1.10
Cd	2.0	0.2	7.2	0.10	3.60
Co	5.8	3.0	14.2	0.52	2.45
Cr	14.0	8.7	29.9	0.62	2.14
Cu	29.1	16.2	68.1	0.56	2.34
Ga	3.0	2.7	4.1	0.90	1.37
Ge	6.7	8.1	2.3	1.21	0.34
Hg	0.28	0.07	0.92	0.25	3.29
Mn	69.6	7.4	258.	0.11	3.71
Mo	11.5	3.8	34.8	0.33	3.03
Ni	30.5	19.6	63.5	0.64	2.08
Pb	110.	22.	377.	0.20	3.43
Sb	0.57	0.34	0.87	0.60	1.53
Se	2.8	1.3	7.3	0.46	2.61
V	15.2	9.1	33.4	0.60	3.67
Zn	510.	12.0	2019.	0.02	3.96
Zr	3.6	1.9	8.8	0.53	2.44

TABLE G-2. AVERAGE DISTRIBUTION OF ELEMENTS AT 1.6
SPECIFIC GRAVITY SEPARATION OF VARIOUS COALS^(G-36)

Element	Concentration (ppm)			Enrichment Factor	
	Raw Coal	Clean Coal	Refuse	Clean Coal	Refuse
Hg	0.22	0.14	0.72	0.64	3.27
F	103.	80.	178.	0.78	1.73
Cr	27.	16.	58.	0.59	2.15
Cu	22.	13.	62.	0.59	2.82
Ni	17.	12.	38.	0.71	2.24
Mn	138.	30.	509.	0.22	3.69
Pb	14.	6.	40.	0.43	2.86
Cd	0.12	0.13	0.10	1.08	0.83

assessments of the quality of natural drainage waters from coal refuse materials. Basically, the metals and sulfate concentrations varied directly with the acidity, with the exception of locally high or low concentrations of particular ions. However, total acidity and total ion concentration were only causally related. This observation implied that the total amount of materials dissolved from the refuse piles was dependent on local conditions such as particle sizes, mineralogy and waste composition, and disposal area drainage patterns, and that relatively high concentrations of dissolved species could accumulate in the effluents from nonacidic waste materials.^(G-30,G-31) Furthermore, other studies have shown that abandoned coal-waste materials will continue to produce waterborne contaminants for years after their disposal.^(G-37,G-38)

It is widely known that coals contain a number of trace elements which are volatilized or converted to volatile forms during combustion and subsequently released in the gaseous products. Finkelman et al.^(G-39) at the U.S. Geological Survey have shown that a large number of trace elements, many of which are toxic, are transported from the hot zone and subsequently deposited in cooler areas by the vapors generated within the burning refuse.^(G-31) This area, however, deserves further attention.

Control Methods. Various techniques for the prevention and treatment of trace elements from acid drainage and waste pile fires have previously been discussed (see Trace Elements and Control, page 169).

Recovery of Trace Elements. Interest in recovering metals from coal wastes has flourished since the forties, when wartime conditions threatened to cut off supplies. Current interest is also stimulated by the realities of external dependence, as more than one-half of the total U.S. requirements of 20 strategic metals and minerals are imported. These metals and minerals in coal and, hence, in coal waste, could supply much of the U.S. demands if they were to be recovered from these materials.^(G-31)

Many processes have been used for pyrite extraction from coal wastes. However, less work has been done on the technology for the recovery of specific trace elements from coal. Several processes for alumina extraction have been developed, and manganese and molybdenum have received attention. Most of the processes investigated, however, require modifications for adaptation to the

various types of wastes, and often the other components in the wastes interfere with the recovery operation. Furthermore, many of the processes are not adaptable to large-scale, commercial operations. (G-31)

Pollution Control Costs

With the use of proper control methods and "good housekeeping", environmental control is technically feasible for most waste streams emanating from coal preparation plants. The question, however, is: "What is practical and to what extent does one have to go to provide an acceptable discharge to the environment?" Moreover, frequently the costs of pollution control for coal preparation (including recovery and reclamation) are such that only a minimal control effort is encouraged.

In the following discussion, the costs for various types of pollution control equipment and techniques have been summarized from Battelle cost estimates in the preliminary report on Pollution Control Technology for Coal Cleaning Processes (June, 1977). (G-23)

Air Pollution Control Equipment. Tables G-3 and G-4 show the installed capital costs and operating costs for air pollution control equipment for hypothetical 500- and 1000-tph coal cleaning plants with the following levels of treatment:

- Type A: Crushing and Sizing Plant
- Type C: Medium-Size Coal Beneficiation Plant
with Air Tables (Pneumatic Cleaning)
- Type F: Fine-Size Coal Beneficiation Plant
with Thermal Dryers

For some plants (Type A and C) more than one particulate control device is applicable; in this case, cost estimates are prepared for each type of treatment. For the Type F plant, an additional cost was included to account for flue gas desulfurization on the thermal dryer. Limestone scrubbing was selected as the basis for the cost estimate due to its more developed state. Although the use of a limestone scrubber may provide more control (for SO₂) than will ever be demanded, the arrangement represents a high level of control sophistication and an extreme upper limit on control costs that might be incurred.

Water Pollution Control Equipment. Table G-5 shows the estimated costs of water pollution control equipment for hypothetical 1000-tph coal cleaning plants with the following levels of treatment:

TABLE G-3. ESTIMATED COSTS OF AIR POLLUTION CONTROL EQUIPMENT FOR
SELECTED 500-TPH COAL CLEANING PLANTS (G-23)

Plant Type	Emission	Quantity	Applicable Control Equipment	Installed Cost of Control Equipment (1977 Dollars)	Annual Operating Cost of Control Equipment (1977 Dollars)
Type A - Crushing and Sizing	Dust from crushing and sizing operation	3,000 cfm	Dust enclosures with dry bag collectors	26,000 (a)	2,600 (e)
			Dust enclosures with high-efficiency wet scrubbers	15,000 (a)	3,000 (f)
Type C - Medium-Size Coal Beneficiation with Pneumatic Cleaning	Dust from crushing and sizing operation	3,000 cfm	Dust enclosures with dry bag collectors	26,000	2,600 (e)
			Dust enclosures with high-efficiency wet scrubbers	15,000	3,000 (f)
	Dust from air tables	120,000 cfm	Primary cyclones followed by dry bag collectors	200,000 (b)	41,000
			Primary cyclones followed by high-efficiency wet scrubbers	110,000 (b)	144,000
Type F - Fine-Size Coal Beneficiation with Thermal Dryers	Dust from crushing and sizing operation	3,000 cfm	Dust enclosures with dry bag collectors	26,000	2,600
			Dust enclosures with high-efficiency wet scrubbers	15,000	3,000
	Thermal dryer off-gas	150,000 cfm	Primary cyclones with high-efficiency wet scrubbers	135,000 (c)	180,000
			Primary cyclones with high-efficiency wet scrubbers followed by limestone scrubbing	4,725,000 (c)	1,350,000

- (a) Includes all of the ductwork and enclosures. Sizing is based on an exposed area of 15 sq ft and a face velocity of 3.5 fpm for a total volumetric flow of 3,000 cfm. The cost of the entire dust collection unit was obtained by multiplying the collector cost by a factor of 2.0.
- (b) Based on an average volume of 14,000 cu ft of exhaust air per ton of feed coal.
- (c) Based on 26,000 dacf of off-gas per ton of coal dried.
- (d) Excludes capitalization, depreciation, and interest.
- (e) Based on 10 percent of installed cost.
- (f) Based on a cost of \$1.00/cfm-yr.

TABLE G-4. ESTIMATED COSTS OF AIR POLLUTION CONTROL EQUIPMENT FOR
SELECTED 1000-TPH COAL CLEANING PLANTS (G-23)

Plant Type	Emission	Quantity	Applicable Control Equipment	Installed Cost of Control Equipment (1977 Dollars)	Annual Operating Cost of Control Equipment (1977 Dollars)
Type A - Crushing and Sizing	Dust from crushing and sizing operation	36,000 cfm	Dust enclosures with dry bag collectors	36,000 (a)	3,600 (e)
			Dust enclosures with high-efficiency wet scrubbers	20,000 (a)	6,000 (f)
Type C - Medium Size Coal Beneficiation with Pneumatic Cleaning	Dust from crushing and sizing operation	6,000 cfm	Dust enclosures with dry bag collectors	36,000	3,600 (c)
			Dust enclosures with high-efficiency wet scrubbers	20,000	6,000 (f)
	Dust from air tables	240,000 cfm	Primary cyclones followed by dry bag collectors	360,000 (b)	80,000
			Primary cyclones followed by high-efficiency wet scrubbers	200,000 (b)	280,000
Type F - Fine Size Coal Beneficiation with Thermal Dryers	Dust from crushing and sizing operation	6,000 cfm	Dust enclosures with dry bag collectors	36,000	3,600
			Dust enclosures with high-efficiency wet scrubbers	20,000	6,000
	Thermal dryer off-gas	100,000 cfm	Primary cyclones with high-efficiency wet scrubbers	250,000 (c)	350,000
			Primary cyclones with high-efficiency wet scrubbers followed by limestone scrubbing	9,250,000 (c)	2,700,000

- (a) Includes all of the ductwork and enclosures. Sizing is based on an exposed area of 30 sq ft and a face velocity of 3.5 fps for a total volumetric flow of 6,000 cfm. The cost of the entire dust collection unit was obtained by multiplying the collector cost by a factor of 2.0.
- (b) Based on an average volume of 14,000 cu ft of exhaust air per ton of feed coal.
- (c) Based on 26,000 dscf of off-gas per ton of coal dried.
- (d) Excludes capitalization, depreciation, and interest.
- (e) Based on 10 percent of installed cost.
- (f) Based on a cost of \$1.00/cfm-yr.

TABLE G-5. ESTIMATED COSTS OF WATER POLLUTION CONTROL EQUIPMENT FOR
SELECTED 1000-TPH COAL CLEANING PLANTS

Plant Type	Effluent	Quantity	Applicable Control Equipment	Installed Cost of Control Equipment (1977 Dollars)	Annual Operating Cost of Control Equipment, per 1000 gal., ^(b) (1977 Dollars)
TYPE B					
Crushing and Sizing with Dry Screening and Wet Beneficiation	Process Water flow: Suspended solids Dissolved solids	3450 gpm	Radial flow thickener or lagoon flocculant	345,000	4.0¢ 2.7¢
			Absorption-activated carbon treatment	1,700,000 ^(a)	3.3-6.6¢ 9.9¢
TYPE D					
Crushing and Sizing with Wet Screening and Wet Beneficiation	Process water flow: Suspended solids	7650 gpm	Mechanical dewatering: Hydroclones Microscreens Pressure filters Thickener or lagoon	150,000 230,000 310,000 510,000 610,000	3.0¢ 2.1¢ 3.9¢ 2.7¢ 1.8¢
TYPE F					
Fine size and Coal Beneficiation with Hydroclones and Thermal Drying	Process water flow: Suspended solids	9,250 gpm	Radial flow thickener or lagoon	560,000 180,000	2.4¢ 1.6¢

(a) Adsorption is not presently used to treat coal cleaning process water, and would not be necessary for treating the recirculating process water for any plant with a closed water circuit.

(b) Including depreciation and interest on capital.

Type B: Crushing and Sizing with Dry Screening
and Wet Beneficiation

Type D: Medium-Size Coal Beneficiation with
Wet Screening and Wet Beneficiation

Type F: Fine-Size Coal Beneficiation with Hydroclones
and Thermal Drying

In generating the treatment costs, it was assumed that all water treatment is performed to satisfy environmental constraints. Actually, much of the treatment, particularly the dewatering treatment, is necessary for operation of the coal cleaning processes. Thus, a portion of the costs cited may be attributed to process requirements rather than environmental requirements. Furthermore, since the use of a closed water circuit is a viable alternative to treatment and release of wastewater, the water most likely to be treated for release to the environment is run-off and leachate from coal storage and coal refuse piles.

Solid Waste Disposal and Reclamation. The Bureau of Mines (BOM) has studied the costs to the coal industry of refuse disposal and reclamation. (G-40) Nine coal waste disposal projects were investigated. Table G-6 shows some typical total capital costs for coal refuse disposal and reclamation, including road preparation, equipment for loading, transportation, refuse disposal, soil covering, and planting. Table G-7 shows the cost of refuse disposal only. This is essentially the cost of loading, transporting, and unloading. Spreading and compacting costs are shown in Table G-8. Finally, Table G-9 shows the costs of soil covering and planting.

The results of the BOM study are that refuse transportation costs ranged from 13 to 39 cents per ton-mile, spreading and compacting ranged from 4 to 28 cents per ton, and soil covering and planting ranged from \$9,070 to \$2,319 per acre. (G-32) These costs did not include the cost of installing or operating leachate collection or surface drainage collection and treatment facilities.

Costs also have been reported by the Meadow Mining Company for refuse disposal from their preparation plant at Beckley, West Virginia. (G-40) That plant has a 600 tph capacity, and is expected to average 35 percent reject throughout its lifetime. Capital expenditures for refuse disposal are shown in Table G-10. Operating costs were not reported, but labor costs were estimated at over \$125,000 per year.

TABLE G-6. CAPITAL COST OF COAL INDUSTRY
RECLAMATION PROJECTS (G-32)

Company	Mine Location	Mine Name and Type	Capital Investment (a)
Bethlehem Mines Corp.	Barrackville, W.Va.	Idamay mine No. 44 (underground)	\$378,000
Bethlehem Mines Corp.	Ellsworth, Pa.	Mine 60 ^(b) (underground)	528,000
Beth-Elkhorn Corp.	Jenkins, Ky.	Hendrix No. 22 (underground)	70,000
Beth-Elkhorn Corp.	Jenkins, Ky.	No. 27 mine (underground)	70,000
Eastern Associated Coal Corp.	Rachel, W.Va.	Joanne mine (underground)	141,000 ^(c)
Hanna Coal Co.	Cadix, Ohio	Georgetown Area (strip mine)	430,000
Pittsburg & Midway Coal Mining Co.	Hallowell, Kans.	Mine 19 (strip mine)	423,000
Pittsburg & Midway Coal Mining Co.	Madisonville, Ky.	Colonial mine (strip mine)	528,000
U.S. Steel Corp.	Uniontown, Pa.	Ginger Hill (underground)	NA

(a) Includes land costs and preparation, roads, loading and transporting equipment, and planting equipment.

(b) Abandoned dumps; refuse from Mines 51 and 58 being disposed at Mine 60 dump by aerial tram.

(c) Estimate.

NA = not available.

TABLE G-7. COST OF COAL REFUSE DISPOSAL (INDUSTRY) (G-32)

Company	Mine Location	Mine Name and Type	Refuse Produced, tons/day	Mode of Transportation	Distance to Disposal Site (One Way), miles	Refuse Disposal Cost, \$/ton mile (1977 Dollars)
Bethlehem Mines Corporation	Barrackville, West Virginia Ellsworth, Pennsylvania	Idamay mine No. 44 (underground)	1,100	Truck	1.0	\$0.39
		Mine 60(a) (underground)	2,800	Truck and aerial tram	1.0 0.5	0.24 0.14
		Hendrix No. 22 (underground)	765	Truck	1.0	0.18
Beth-Elkhorn Corporation	Jenkins, Kentucky Jenkins, Kentucky	No. 27 mine (underground)	1,170	Conveyor belt and truck	1.0	0.18
Eastern Associated Coal Corporation	Rachel, West Virginia	Joanne mine (underground)	600	Truck	1.0	0.23
		Georgetown Area (strip mine)	4,164	Truck	1.0	0.35
Hanna Coal Company	Cadiz, Ohio					
Pittsburgh & Midway Coal Mining Company	Hallowell, Kansas Madisonville, Kentucky	Mine 19 (strip mine)	2,400	Truck	2.0	0.14
		Colonial mine (strip mine)	1,100	Truck	2.0	0.14
		Ginger Hill (underground)	4,500	Underground rail mine cars and carryall	4.0	0.13(b)
U.S. Steel Corporation	Uniontown, Pennsylvania					

(a) Abandoned dumps; refuse from Mines 51 and 58 being disposed at Mine 60 dump by aerial tram.

(b) Direct cost only.

TABLE G-8. COST OF COAL REFUSE SPREADING AND COMPACTION (INDUSTRY) (G-32)

Company	Mine Location	Mine Name and Type	Spreading and Compaction Equipment	Refuse Handled, tons per day	Handling Cost per ton, (1977 Dollars)
Bethlehem Mines Corp.	Barrackville, W.Va.	Idamay mine No. 44 (underground)	Trucks and bulldozer	1,100	\$0.04
Bethlehem Mines Corp.	Ellsworth, Pa.	Mine 60 (a) (underground)	Ditto	2,800	.07
Beth-Elkhorn Corp.	Jenkins, Ky.	Hendrix No. 22 (underground)	"	765	.23
Beth-Elkhorn Corp.	Jenkins, Ky.	No. 27 mine (underground)	"	1,170	.18
Eastern Associated Coal Corp.	Rachel, W.Va.	Joanne mine (underground)	"	600	.15 (b)
Hanna Coal Co.	Cadiz, Ohio	Georgetown Area (strip mine)	"	4,164	.14
Pittsburg & Midway Coal Mining Co.	Hallowell, Kans.	Mine 19 (strip mine)	(c)	2,400	.28
Pittsburg & Midway Coal Mining Co.	Madisonville, Ky.	Colonial mine (strip mine)	Bulldozer	1,100	.17
U.S. Steel Corp.	Uniontown, Pa.	Ginger Hill (underground)	Carryall	4,500	(d)

(a) Abandoned dumps; refuse from Mines 51 and 58 being disposed at Mine 60 dump by aerial tram.

(b) Estimated.

(c) Refuse disposed in pit areas. No spreading or compacting.

(d) Included in the cost of refuse disposal (see Table G-7).

TABLE G-9. COST OF SOIL COVERING AND PLANTING (COAL INDUSTRY) (G-32)

Company	Mine Location	Mine Name and Type	Soil Cover, tons per acre	Soil Cover, cost per acre (a) (1977 Dollars)	Vegetation Planted	Planting Cost per Acre (b) (1977 Dollars)
Bethlehem Mines Corporation	Barrackville, West Virginia Ellsworth, Pennsylvania	Idamay mine No. 44 (underground) Mine 60(c) (underground)	3,300 21,750	1,174 15,400(d)	Grasses, black locust, white pine White pine, perennial rye, Kentucky fescue, Serecia lespedeza	232 622(e)
Beth-Elkhorn Corporation	Jenkins, Kentucky Jenkins, Kentucky	Hendrix No. 22 (underground) No. 27 mine (underground)	4,350 --	1,800 --	White pine, annual rye, Kentucky fescue, Serecia lespedeza White pine, short leaf pine, loblolly pine	70 85(f)
Eastern Associated Coal Corporation	Rachel, West Virginia	Joanne mine (underground)	13,235	1,863	Grasses, locust, white pine	209(g)
Hanna Coal Company	Cadiz, Ohio	Georgetown Area (strip mine)	4,538	2,251	Kentucky fescue, orchard grass, crown vetch	68
Pittsburgh & Midway Coal Mining Company	Hallowell, Kansas Madisonville, Kentucky	Mine 19 (strip mine) Colonial mine (strip mine)	8,700 6,525	1,000 1,000	Kentucky fescue, Serecia lespedeza, locust trees Kentucky fescue, love grass, Serecia kobe, Serecia lespedeza	70 70
U.S. Steel Corporation	Uniontown, Pennsylvania	Ginger Hill (underground)	3,263	937	Crown vetch, black locust, pine trees, perennial rye grass, Kentucky fescue	641(h)

(a) Includes soil, transportation, spreading, and compacting.

(b) Costs not footnoted are those for planting grasses and trees on soil cover not conditioned.

(c) Abandoned dump; refuse from Mines 51 and 58 being disposed at Mine 60 dump by aerial tram.

(d) Privately contracted at 30 cents per ton.

(e) Includes cost of lime, paper mulch, fertilizer, grass seed applied by hydroseeding, and trees planted by hand. Weighted average cost for 1966, 1969, and 1970-71 projects.

(f) Soil cover not used. Trees and grasses planted directly on refuse not previously conditioned.

(g) Includes cost of lime, mulch, fertilizer, seed, and trees.

(h) Includes cost of soil conditioning, hydroseeding, and tree planting. Direct cost only.

TABLE G-10. CAPITAL EXPENDITURES FOR REFUSE DISPOSAL
SYSTEMS AT MAPLE MEADOW PREPARATION PLANT,
BECKLEY, WEST VIRGINIA^(G-40)

Item	Capital Cost, 1977 Dollars
Vacuum filter for dewatering refuse	\$308,000
700-ft belt conveyor, plant to rock bin	164,000
Rock bin, 250-ton capacity	51,000
1,600-ft belt conveyor, rock bin to disposal area	267,000
Mine car system for rock haulage	51,000
Front end loader	88,000
35-ton rear dump hauler	77,000
Bulldozer for refuse compaction	77,000
Clearing of refuse disposal area	27,000
Installation of drainage system under disposal site	26,000
Construction of road, plant to disposal area	23,000
Diversion ditch around refuse area	21,000
Sludge pond and dam at refuse area	25,000
Emergency ponds for static thickener and necessary piping	23,000
TOTAL COST	\$1,228,000

Transportation Barriers

Introduction

In the past, the high costs of transporting coal in its solid form restricted its market areas relative to industrial fuel oil and natural gas for heating and steam generation. More recently, shortages of natural gas and indigenous supplies of petroleum, coupled with the high costs of imports, have enlarged the potential markets for coal.

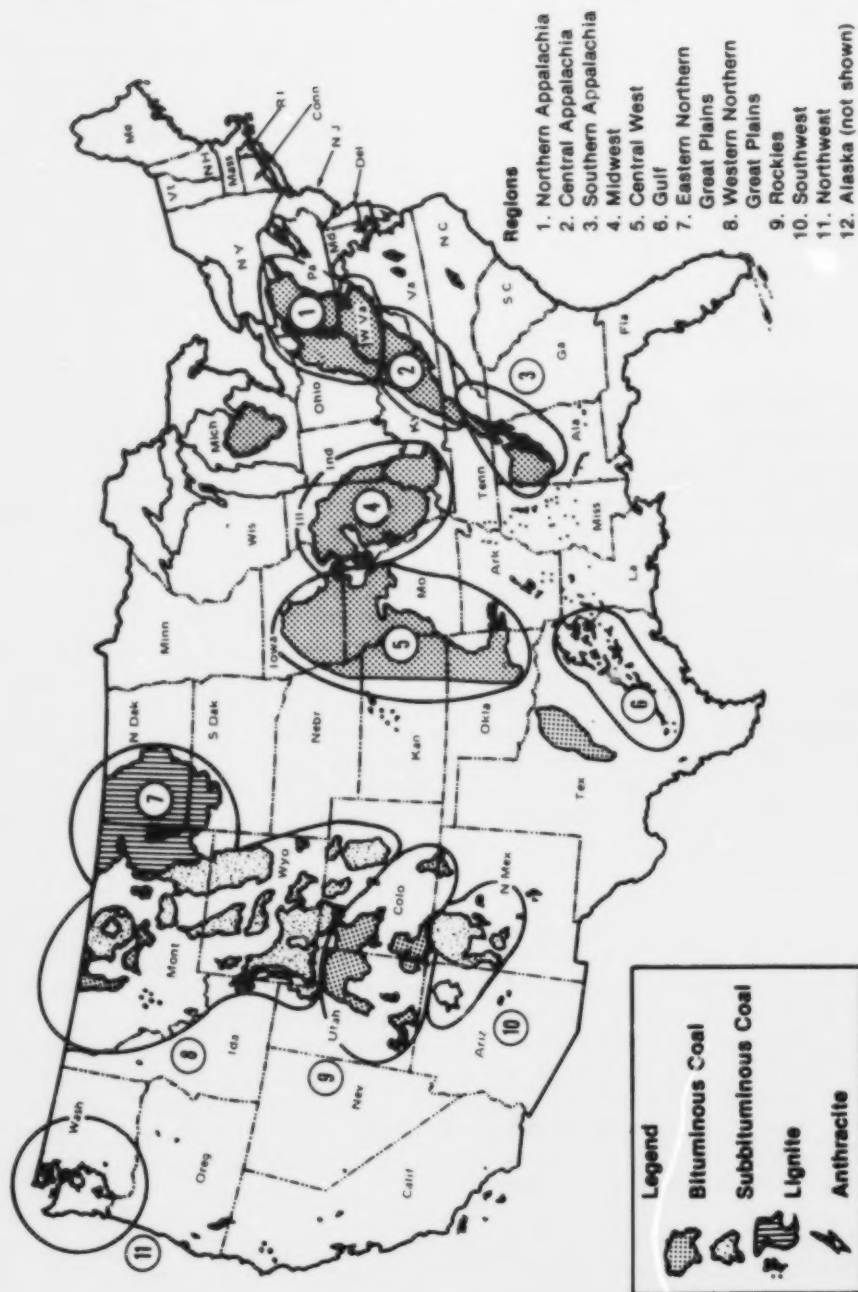
The National Energy Plan as proposed by President Carter envisions an increase in U.S. coal production from about 660 million tons in 1976 to almost 1.3 billion tons in 1985. To achieve this growth rate will require a vastly accelerated program to expand production capabilities for both high and low sulfur coals.

Supply/Demand Relationships

Major coal supply regions are shown in Figure G-1.^(G-45) In 1976, almost 80 percent of the coal was produced in regions east of the Mississippi (Regions 1, 2, 3, and 4 in Figure G-1). However, most of the low sulfur coals are western deposits requiring long distance shipments to major market areas. The generally lower Btu content of the western coals adds to the high transportation cost.

A breakdown of estimated coal production by region for various years to 1990 is shown in Table G-11.^(G-45) The National Energy Plan^(G-46) calls for the following coal demand pattern in 1985, compared with the Federal Energy Administration (FEA) estimate shown in Table G-11, as follows:

	<u>National Energy Plan</u>	<u>FEA Estimate</u>
Electric utilities	780 million tons	715 million tons
Industrial use	395 million tons	240 million tons
Residential		5 million tons
Exports	<u>90 million tons</u>	<u>80 million tons</u>
TOTAL	1265 million tons	1040 million tons



Source: 1976 Energy Outlook, Federal Energy Administration, Washington, D.C.

FIGURE G-1. COAL SUPPLY REGIONS

TABLE G-11. COAL PRODUCTION BY REGION (G-45)
(Million Tons)

Region	1976 ^(b)	1974 ^(a)	1980 ^(a)	1985 ^(a)	1990 ^(a)	1985 ^(c)	1985 ^(d)
1 Northern Appalachia	176	171	163	183	199	200	260
2 Central Appalachia	188	184	269	297	322	310	330
3 Southern Appalachia	23	20	24	25	24	30	35
4 Midwest	<u>136</u>	<u>135</u>	<u>96</u>	<u>156</u>	<u>176</u>	<u>176</u>	<u>220</u>
Subtotal East	523	510	552	661	721	716	845
5 Central West	25	9	9	9	10	80	80
6 Gulf	25	8	17	21	21	80	80
7 Eastern Northern Great Plains	11	8	14	31	45	31	31
8 Western Northern Great Plains	59	35	185	274	464	354	255
9 Rockies	18	14	16	19	21	40	25
10 Southwest	19	14	5	21	21	40	25
11 Northwest	4	4	1	4	4	4	4
12 Alaska	-	<u>1</u>	<u>(e)</u>	<u>(c)</u>	<u>(e)</u>	<u>(e)</u>	<u>(e)</u>
Subtotal West	136	93	247	379	586	549	420
National Total	659	603	799	1,040	1,307	1,265	1,265

(a) 1976 National Energy Outlook.

(b) U.S. Bureau of Mines.

(c) Battelle estimate of distribution of coal production by region to meet National Energy Plan goals with expanded utilization of western low-sulfur coals.

(d) Battelle estimate assuming Best Available Control Technology (BACT) requiring use of scrubbers on new installations.

(e) Less than 500,000 tons.

The major difference between the two estimates is the emphasis in the Plan on expanded use of coal by industry and utilities to reduce requirements for fuel oil and natural gas.

Transportation Requirements

A major uncertainty in transportation requirements involves possible changes in geographical locations of coal deposits needed to service industrial requirements as opposed to utility requirements. In the absence of the development and acceptance of methods to reduce the sulfur content of eastern coals, many industries would prefer low-sulfur western coals even at higher prices to avoid the problem in meeting air-quality standards through use of stack-gas controls. On the other hand, adoption of Best Available Control Technology (BACT) requirements mandating scrubbers and new installations would favor use of high-sulfur eastern coals, if available at substantially lower delivered prices. A possible distribution in regional coal production by 1985 for each of these conditions also is presented in Table G-11 to show the sizable differences in required production that may be involved. Establishing regulations permitting expanded use of physically cleaned coal would also favor the higher use of eastern coals.

In 1976, U.S. coal shipments by class of purchases and by transportation mode were as shown in Table G-12.^(G-47) All-rail shipments accounted for about 54 percent of the total followed by barge shipments at 17.6 percent, trucks at 11.3 percent, and specialized transport methods (trainways, conveyors, private railroads, slurry pipelines, etc.) at 10.9 percent. Great Lakes shipments in colliers were about 5 percent, and tidewater shipments were only 1 percent of the total.

As shown in Table G-11, coal production from mines east of the Mississippi was almost 80 percent of the total in 1976. Transportation networks for the movement of coal from these mining areas to consumption points are well established. Shipments from mine to consumption point average less than 300 miles with only a few specific hauls exceeding 500 miles. Rates for unit trains have been negotiated permitting large-tonnage shipments of coal at rates significantly lower than single-car rates. Extensive inland-waterway systems have been developed providing low-cost shipment by barge. Trucks and/or

TABLE G-12. U.S. COAL SHIPMENTS BY CLASS OF PURCHASER AND
BY TRANSPORTATION MODE, 1976 (G-47)
(Millions of Tons)^(a)

Class of Purchaser	Total	All Rail	Great Lakes	River and Ex-river ^(a)	Tidewater	Truck	Train, Conveyor, Private R.R., etc.
Electric Utilities	463	246	17	82	1	53	65
Coke & Gas Plants	93	51	12	23	4	3	(a)
Retail Dealers	4	2	(b)	(b)	(b)	1	(a)
All Others	<u>53</u>	<u>32</u>	<u>4</u>	<u>3</u>	<u>(b)</u>	<u>13</u>	<u>2</u>
Total	613	331	33	108	5	69	67
Percent of Total		54	5.4	17.6	0.8	11.3	10.9

(a) Shipments via river to customers receiving coal alongside the river and to customers located inland from a river unloading facility are designated as river and ex-river, respectively.

(b) Negligible.

conveyor systems are utilized when distances from the mines to consumption or transfer point are only a few miles.

By 1985, demand for eastern coal is anticipated to increase by 200 to 300 million tons, or between a 37 and 62 percent growth over 1976 production. If uniformly distributed, even the highest increase could probably be handled with relatively minor improvements in the present transportation systems. However, to meet this goal, production in Region 2 (Central Appalachia) will have to increase by up to 75 percent, which could create bottlenecks in the present transportation network.

In 1976, almost 40 million tons of low-sulfur coal were shipped from Region 8 in Montana and Wyoming to west north central and east north central states. (G-47) By 1985, large quantities will also be shipped from Regions 8, 9, and 10 to southwestern and southern states replacing natural gas use in steam generation and process heating. Total demand for coals from Regions 8, 9, 10, and 11 (Washington) may reach more than 400 million tons by 1985 compared with 100 million tons in 1976. Most of this increased demand will involve shipments to destinations of 900 to 1200 miles, or more, from the mine. Substantial improvements in present rail networks will be needed to handle this vast growth in tonnage movements. (G-48, G-49) The high cost involved in developing these systems has awakened interest in the use of coal slurry pipelines as an alternative to unit trains.

Large increases in production of lignites in Texas and the Dakotas (Regions 6 and 7) are also anticipated by 1985. However, the low Btu value of lignites will probably restrict shipments to destination points close to the mine, using trucks and/or conveyor systems.

Barriers

Substantial expansion and improvements in transportation capabilities will be needed to ensure timely movement of coal from the mine to points of consumption. Railroads are anticipated to continue as the principal mode for long distance shipments. Inland waterways offer lower-cost means where available. Combination rail-water shipments may be competitive with unit trains to specific locations. Coal slurry pipelines may also offer economic alternatives for high-volume, long distance shipments and to areas not presently serviced by adequate rail facilities.

Railroads are faced with formidable tasks in increasing capabilities to meet the anticipated growth in coal shipments. It is estimated that two-thirds of the 1985 coal demand for new electricity generation units will be transported by rail^(G-50) and a higher percentage of shipments to industrial plants will probably use that mode.

Many eastern rail systems have badly deteriorated roadbeds which will have to be upgraded and replaced. Both eastern and western railroads will need to increase rail line capacities at selective points to avoid system overloads. New branch and access lines will be required to serve mine development. Facilities must be constructed in conjunction with mining and utility companies to handle loading and unloading operations for new fleets of unit trains that must be purchased, or obtained through leasing arrangements. However, the most critical problem may be in obtaining the necessary financing for the needed capital improvements.

Manalytics, Inc. in a recent study^(G-51) for the Electric Power Research Institute (EPRI) has identified rail and waterway capabilities for the transportation of coal in 1985 and beyond. Detailed analyses were made of the capabilities and existing rail and barge networks for a high-demand scenario (1,514 million tons) and a low-demand scenario (1,242 million tons). The low-demand scenario now closely approximates the tonnage requirements to meet the National Energy Plan. However, the higher demand scenario more closely resembles regional production patterns that will be followed if BACT requirements for scrubbers are required or if air quality regulations will permit the use of physically cleaned coals. In either case, the capability limitation identified in that study is indicative of major transportation bottlenecks that will be faced over the next several years.

The study examined projected traffic flows over 162 by-links passing through 16 major geographical barriers. In the high-demand scenario, overloaded systems were found in the traffic from the Appalachian Region to the middle Atlantic states, Ohio, and to southern states in the Missouri and Mississippi River crossings, and in links between the west north central and southwestern states. In the low-demand scenario with higher utilization of western coals, major blockages were from Wyoming and Montana to the east, west, and south; and from Appalachian regions to the northeast and south. However, in most instances, consumption area requirements could be met by rerouting over

longer distances through alternative railroad paths or through use of waterways for a portion of the movement. (G-51)

Manalytics, Inc. also examined waterway transportation capabilities. Other than seasonal restrictions on the Great Lakes, Upper Mississippi, and Missouri River systems, capacity limitations may be encountered by 1985 at four loads on the Ohio River and its tributaries, one load on the Upper Mississippi River, and loads on the Gulf Intracoastal Waterway both east and west from New Orleans. (G-51)

Transport Economics

Water transportation provides the lowest-cost movement of coal. This has led to the establishment of electric utilities adjacent to major waterways wherever available. Also, in many cases combination rail-water transportation offers a lower cost than rail shipments. Recent examples of combined rail-water shipments comprise (1) movement of coal by rail from Montana to Superior, Wisconsin, and transshipment through the Great Lakes to Detroit, Michigan, and (2) rail transport from Wyoming to the St. Louis, Missouri area and transshipment by barge to Ohio.

Unfortunately, most coal deposits and consumption points are not directly accessible to water transport. The high cost of truck and conveyor transport restricts their economical utilization to shipments of only a few miles from the mine to consumption or transfer points.

Transportation of coal accounts for about 20 percent of total rail tonnage and is a much higher proportion of the total tonnage movements of several eastern railroads. Networks have been established with branch lines to the coal mines. In recent years, unit trains have become a relatively low-cost efficient means of handling high-volume, regular shipments from the mine to a single consumption point within a distance of 100 to 500 miles. A summary of nine case studies of unit train operations is shown in Table G-13. (G-52) At the time of the study (1970) costs per ton mile ranged from about 4 to 8 mills (haulage tariff rate). A combination of large storage capacity and rapid loading methods was used at each installation. However, there was a large variety in the type of storage and the extent of coal preparation. There was also a variance in ownership of their unit train cars between producer, consumer, and railroad.

TABLE G-13. SUMMARY OF NINE CASE STUDIES OF UNIT TRAIN OPERATIONS (G-52)

General information	Inland Steel Mine	Valley Camp No. 3 Mine	Captain Mine	Lancashire No. 20 Mine	Orient No. 5 Mine	Bellcoal Inc.	Matthews Mine	Bell & Zoller No. 9 Mine	Trenton Channel Facilities
Location	Illinois	West Virginia	Illinois	Pennsylvania	Illinois	Kentucky	Tennessee	Kentucky	Ohio
Source of production	Underground	Underground	Strip	Underground	Underground	Strip	Underground	Underground	Strip
Reserves, years	40	50	30	25	20	35	20	27	40
Quality of coal	Metallurgical and steam	Steam	Steam	Steam	Steam	Steam	Steam	Steam	Steam
Calorific value, Btu/lb	12,584, 11,000	13,500	10,780, 11,200	13,013	11,000	12,720	13,200	11,520	12,200
Date of first unit train	July 1968	Jan. 1965	Oct. 1964, Jan. 1966	Aug. 1967	July 1968	Mar. 1966	Jan. 1968	Sept. 1967	Sept. 1967
Type of storage	3 silos	1 silo	Ground	Ground	Ground	Ground	Ground	Ground	Ground
Capacity of storage, tons	42,000	11,000	94,000	36,000	30,000	14,400	40,000	60,000	55,000
Shape of storage	Silo	Gilo	Windrow	Conical	Conical	Conical	Conical	Kidney	Conical
Ventilation of storage	Fan	Fan	Fan	Fan	Fan	Natural	Natural	Fan	Natural
Coal preparation	Clean	Clean	Blended, clean	Clean	Raw	Raw	Clean	Raw	Raw
Size of coal	1.5 in. by 0, 0.75 in. by 28 mesh	2 in. by 0	3 in. by 0, blended; 2 in. by 0, clean	1 in. by 0	1.5 in. by 0	3 in. by 0	5 in. by 0	2 in. by 0	4 in. by 0
Number of unit trains	1	1	2	1	1	1	1	1	1
Haulage distance, miles, one-way	279	450	306,354	180	130	333	457	129 rail, 275 barge	317
Cars per train	125	105	126, 102	105	70	84	96	Hopper	82
Type of cars	Hopper	Hopper	Gondola	Hopper	Hopper	Hopper	Gondola	Leased by railroad	Gondola
Capacity of car, tons	100	50-84	100	100	100	80	110	100	100
Ownership of cars	Consumer	Railroad	Consumer	Consumer	Railroad	Railroad	Leased by producer	Leased by producer	Leased by producer
Minimum tons per shipment	12,500	7,000	12,600, 10,200	10,500	7,000	7,000	10,000	7,500	8,200
Minimum tons per year	1,500,000	-	3,300,000, 1,400,000	1,800,000	1,000,000	1,400,000	1,500,000	1,750,000	1,800,000
Loading track layout	Rail loop	2 single tracks	4 parallel tracks	Single track	Single track	Single track	Rail loop	Rail loop	Single track
Means of moving cars while loading	Locomotives	Locomotives	3 car hauls	Locomotives	Locomotives	Locomotives	Locomotives	Locomotives	Locomotives
Rate of car movement, fpm	22	25	20	21	30	24	30	30	28
Loading rate, tph	4,000	2,500	2,700	3,200	2,400	2,600	3,000	3,300	3,000
Cost per ton (haulage tariff rate)	\$1.50	\$3.53	\$1.35, \$1.83	\$1.50	\$1.00	\$1.79	\$1.75	\$1.01 rail, \$1.30 barge	\$1.66
Cost per ton mile (haulage)	\$0.0054	\$0.0078	\$0.0044, \$0.0052	\$0.0083	\$0.0077	\$0.0054	\$0.0038	\$0.0078, \$0.0047	\$0.0032
Percent of production shipped by unit train	100	65	100	100	57	100	100	100	55
Shipping cost per million Btu	\$0.060, \$0.068	\$0.131	\$0.063, \$0.082	\$0.058	\$0.045	\$0.070	\$0.066	\$0.044, \$0.056	\$0.068

Most of the western coal will require shipments of 800 to 1200 miles to major consumption areas. While actual costs per ton mile for unit trains may be lower than rates by eastern carriers, the lower Btu content of the western coals and long distances of the shipments add significantly to the delivered price of the coal. Coal slurry pipelines are being considered as alternative methods of coal delivering, particularly to the southwest. Other possible alternatives include coal gasification with pipeline transmission and electric power generation with extra high voltage transmission. Neither of these two latter alternatives is anticipated to be a major substitute prior to 1990.

In 1975, the Consolidation Coal Company built a 108-mile, 1.3 million ton-per-year, 10-inch line from Cadiz, Ohio, to Lake Erie. This system was mothballed in 1963 when much lower rail rates were obtained.

In 1970, the Black Mesa pipeline operated by the Southern Pacific Transportation Company initiated service. This 273-mile-long, 18-inch diameter pipeline transports about 4.8 million tons of coal annually from a Kayenta, Arizona, mine to the Majone Power Plant on the Colorado River in southern Nevada. (G-53, G-54) The decision to construct the pipeline was made as a lower cost alternative to building a new railroad through a more circuitous mountainous route between the two locations. The successful operation of this line at 98 to 99 percent availability has awakened interest in the construction of other coal slurry pipelines in western states.

Salient statistics on six coal slurry pipelines that are in various stages of planning are presented in Table G-14. These projects are involved in controversies between advocates of the pipelines and affected railroads regarding the pluses and minuses of the environmental effects of pipelines versus rail haulage and the relative costs and benefits of alternative systems. (G-53)

Water availability is the major technical factor inhibiting the installation of coal slurry pipelines. Approximately one ton of water is required per ton of coal transported, so slurry pipelines must compete with alternative uses for limited supplies in the arid western region.

However, acquiring the right of environmental domain is the most important constraint facing the building of coal slurry pipelines. Federal and/or state legislation will be required for permission to pass under railroad rights-of-way. This legislation is being fought by several railroads as detrimental to

TABLE G-14. U.S. COAL SLURRY PIPELINES UNDER
CONSIDERATION (G-53, G-54)

System and Location	Length, miles	Diameter, inches	Annual Capacity, millions of tons/year
Nevada Power Company (Utah/Nevada)	180	24	10
Energy Transportation Systems, Inc. (Wyoming/Arkansas)	1036	38	25
Houston Natural Gas Company (Colorado/Texas)	750	28	10
Gulf Interstate, N.W. (Wyoming/Oregon)	800	20-24	10
Brown & Root/ Texas Eastern (Montana/Houston)	1100	36-40	22-29
Salt River Project (New Mexico/Arizona)	180	16	4

the national interest in "skimming the cream" off the railroad's coal business for the possible benefit of a few large generating complexes at the expense of other consumers and the railroads.

There is also disagreement over the relative economics of coal slurry pipelines versus unit train shipments.

Coal slurry pipelines are highly capital intensive. Costs per ton mile decrease with increasing volume shipments on a continuous basis. In difficult terrain, where present rail systems do not exist, pipelines have been shown to be competitive with shipments of 5 million tons of coal annually, as witness the Black Mesa pipeline.

Where railroads exist, relative economics are dependent on the extent to which the rail system must be upgraded to meet the capacity requirements. Costs per ton mile using unit trains are relatively constant for volume shipments above 3 to 5 million tons annually to a given location, while coal slurry pipeline costs decrease with increasing volume. Analyses made by utilities and pipeline companies indicate substantially lower costs for high volume pipeline shipments, particularly when comparative inflation rates are considered over the expected life of the operation. (G-55,G-56,G-57) Conversely, another recent study indicates lower costs for rail shipments, including new rails, for existing systems. (G-58)

Comparisons between pipeline and railroad costs are shown in Figure G-2. These data are from a study made by O. L. Anderson and Mike Rogozen. (G-57) Data published in Reference G-56, and cost estimates made by S. L. Soo for a 1100-mile rail system from Wyoming to Arkansas (G-58) are shown for comparison.

Obviously, there is considerable disagreement in cost estimates made by different investigators. This indicates that careful cost comparisons are needed in reaching a decision regarding the most advantageous mode of coal shipment to utilize over a wide range of tonnages to specific site locations.

Conclusions

It has been generally assumed that eastern railroads will be able to handle the increased coal tonnages as they develop through 1985, provided sufficient financial incentives are made available to improve the rail systems and to purchase or lease the needed unit trains. As pointed out earlier,

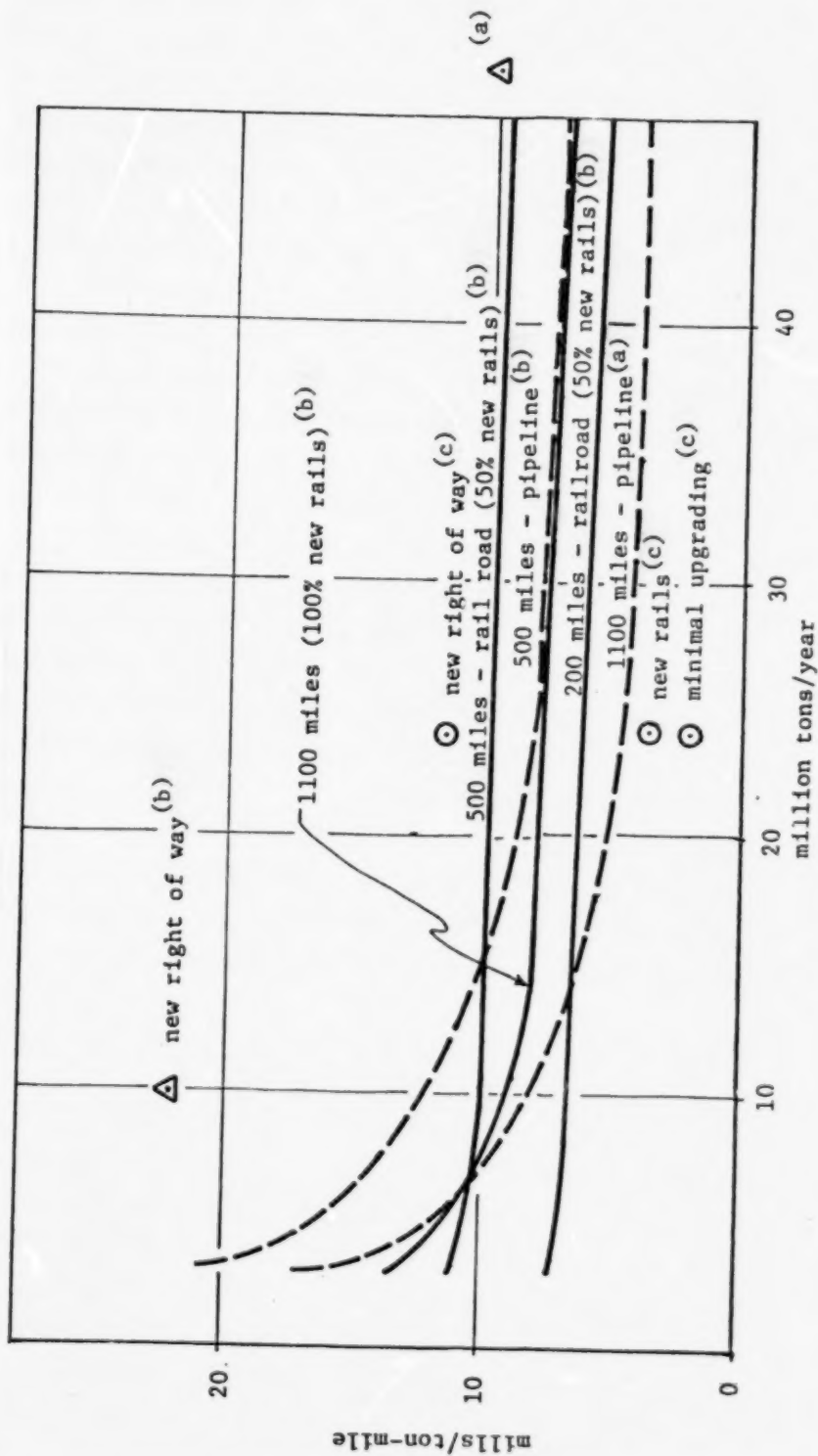


FIGURE G-2. ESTIMATED COST COMPARISONS OF COAL SLURRY PIPELINES VERSUS RAILROAD SHIPMENTS WITH UPGRADING (G-56--G-58)

bottlenecks may develop in limited capacity of certain links from Appalachian Regions to major consuming centers. If and when new rail systems are needed, slurry pipelines either singly or in combination with water transport may provide viable alternatives from new large mines in the 5- to 10-million ton per year production range. Six potential consumption sites located in Georgia, Kentucky, New York, North Carolina, and Ohio have been suggested as possible prospects for slurry pipelines with annual requirements as low as 3.5 to 4 million tons. (G-54)

The possible use of slurry pipelines in combination with coal cleaning and preparation plants may improve the overall economics.

There is strong likelihood that one or more coal slurry pipelines will be built to transport western coals. Water availability and economics will determine the importance of this mode in comparison with expansion of needed rail systems.

The capital requirements to handle the increased transport of coal by all modes will amount to several billion dollars. Manalytics, Inc. in its recent study interviewed rail and waterway equipment manufacturers and determined that facilities can be made available for producing as many as 200,000 hopper cars, 20,000 locomotives, 4000 towboats, and 14,000 barges by 1985, if sufficient demand evolves. (G-51) Facilities needed to manufacture the needed line pipe, pumps, and auxiliary equipment are also believed to be adequate.

Thus, if sufficient lead time and suitable financial incentives are provided, it is believed that potential bottlenecks could be eliminated, or the effects minimized, with only minor dislocations in the desired movement of coal from the mines to major consumption areas.

Extent of Appreciation for PCC Benefits

The majority of potential PCC investors contacted in the course of this study expressed surprise that PCC should be considered a sulfur removal strategy for boilers subject to anticipated New Source Performance Standards (NSPS) revisions. Even those who were aware that Section 111(a)(1) of the 1977 amendments to the Clean Air Act granted the EPA Administrator authority to permit credit toward the percentage removal requirement for precombustion cleaning, were skeptical that PCC in combination with FGD would prove a least-cost compliance option.

Although it is difficult to generalize on what potential investors know or perceive as PCC benefits in combination with FGD and what potential benefits they are unaware of, it can be said that the following PCC benefits are reasonably well appreciated:

- Reduced effective transportation costs
- Reduced ash disposal costs, both capital investment and operating cost savings
- Possibility of reduced FGD capacity, hence, reduced investment in FGD
- Reduced FGD operating and maintenance costs, including lime/limestone requirements
- Reduced pulverizing costs.

Other benefits which have been associated with the combination of PCC and FGD appear to be less appreciated. These include:

- Reduced variability in the sulfur content of coals, hence, possible scaling down of FGD design capacity as needed to take variability into account
- Reduced likelihood of need for FGD reheat
- Increased FGD reliability
- Possible increased probability that boilers may continue to operate in the event of an FGD malfunction or in the event of an energy emergency
- Reduced boiler maintenance costs, because PCC produces less corrosive coal and coal with more uniform characteristics
- Reduced particulate control costs
- Ability to use very high sulfur, and thus, relatively cheap coals in boilers subject to NSPS revisions
- Enhanced economic prospects in those areas where very high sulfur coals are mined.

It should be noted that an appreciation of the range of possible PCC benefits, as well as costs, in the revised-NSPS case may to a large extent be a function of the depth of investigation devoted to this alternative. It is understandable for investors in the revised-NSPS case to ignore the largely unproven PCC technologies (though perhaps not a great deal less proven than FGD technologies) if their benefits are not dramatically great in a limited number of areas.

Furthermore, it is much easier to focus on one technology, FGD, with one particular type of coal in mind, medium-to-high sulfur content (depending upon the revised-NSPS ceiling level), than it is to consider a range of technologies (blending might be included as well) applied to a range of coals. Of course the proportion of pyritic sulfur in these coals would be another very important variable to consider.

Our findings on the extent to which potential investors appreciate PCC benefits for NSPS and SIP standards applications indicate a somewhat better appreciation for PCC benefits than is the case for revised-NSPS applications. Even where FGD/PCC combinations might be applicable, there is somewhat greater knowledge of the beneficial role PCC might play. Hence, it appears that the percentage removal requirement associated with NSPS revisions is what inhibits investigation of PCC for that case.

For the NSPS and SIP standards cases, the fact that use of PCC alone might achieve compliance would tend to simplify calculations. (However, as this analysis unfolds it will become clear--if it is not already--that such calculating is not facile.) On the other hand, the fact that there are so many options--for NSPS or SIP compliance--e.g., natural low-sulfur coals, PCC, blending, FGD, and numerous combinations with higher sulfur coals--tends to complicate the issue and, thus, have the effect of clouding the specific benefits attributable to PCC.

In general, potential investors view PCC benefits for NSPS and SIP applications as including:

- Reduced transportation costs, the extent of which is determined principally by the location or locations of PCC plant(s) and by the availability and cost of certain types of transport equipment
- Reduced ash disposal costs, and FGD investment and operating costs
- Ability to use indigenous higher sulfur coals, rather than having to contract primarily for western lower sulfur coals
- Reduced need to blend coals, the chemical characteristics and contractual characteristics of which may not be well matched
- Reduced boiler maintenance costs
- Reduced sulfur variability, hence an opportunity to comply with SIPs.

Despite these advantages--some certainly more fully appreciated than others--there has not been a tremendous rush to invest in PCC for sulfur

removal purposes. Greater dissemination of information concerning PCC benefits would certainly appear to be in order. However, greater publicity alone will not produce PCC investment. To continue to describe why this is so, we turn to the second set of institutional barriers to adoption of PCC as a sulfur removal strategy.

Particular Constraints Faced by Different Would-be Investors

Special problems with a PCC investment are faced by coal companies, electric utilities, and other industrial coal users. Under this heading, we consider the barriers that each would see in a PCC investment. Further, because one response to these problems would be to attempt to form new institutional arrangements--e.g., joint ventures, cooperatives, consortia--to facilitate such investment, we consider also some of the problems there are in establishing and maintaining these relationships.

Coal Companies. For the purposes of this analysis, coal companies are distinguished by their size and asset backing. In effect, it may be said that there are two types of coal companies which may be seen as potential investors in PCC: large coal companies or ones that are subsidiaries of large firms, and small independent coal companies.

Large Coal Companies. By large companies, for purposes of this analysis, we mean firms that now have coal mines or are in a position to make investments in coal mines which produce at least 1 million tons per year. Currently, about 5 percent of the nation's mines produce at this rate (contributing to greater than 60 percent of total annual production).

Coal cleaning, as now practiced principally for ash removal purposes, is performed almost exclusively at mines of this capacity, or greater. In the future, if investment in PCC for sulfur removal purposes is to be made by individual coal companies, such firms will in all likelihood be those which operate mines of at least this capacity. In fact, to take advantage of economies of scale and to produce in a competitive market, investment in PCC may imply significantly higher mine production rates, perhaps upwards to 2 million

tons per year, a figure which corresponds with the 500 tons per hour PCC plant capacity used in most engineering studies.

In 1976, there were only 26 mines outside the western states at which production met or exceeded 2 million tons. These mines are owned by just 11 firms. (Three are subsidiaries of petroleum companies.)

In general, coal produced at large mines is covered to a very significant extent by long-term contracts. These contracts are believed necessary to protect the large capital investments and attendant risks associated with large mine development. Should large coal companies take it upon themselves or be requested, e.g., by a utility, to invest in PCC, such investment would simply be another item requiring financial protection.

From a financial standpoint, it would appear not to matter whether such protection be for one year, five years, or longer--that is, so long as the coal company's investment is recovered and it earns an appropriate inflation-adjusted rate of return on that investment.

From an economic, or competitive, point of view, it matters very much whether an investment is recovered and return realized over one, five, or more years. Clearly the more rapid the recovery, the higher must be the cost of a ton of cleaned coal. At some (rapid) rate, the cleaned coal loses its economic attractiveness.

By the same token, the cost recovery period cannot be expected to be very long, e.g., 15 years, since the longer the period of time, the longer the investment may be at risk. The longer an investment of this type is at risk, the greater must be expected to be the anticipated return on investment. Furthermore, it should be pointed out that in situations where borrowed investment funds are involved, lending periods very rarely exceed six to nine years.

All of this suggests that large companies may not be averse to investing in PCC so long as firm contractual commitments are involved. These commitments are likely to be in existence in any case, since large mines are not generally developed without them. Implicit in this discussion is the notion that coal purchases subject to long-term contracts do not view these contracts as realistically abrogable. (This issue is addressed at length in Appendix C.) Given the way large existing and new mines are protected financially (that is, with long-term contracts), there would appear to be few problems with large coal companies investing in PCC. In fact, so long as a large volume purchaser is

willing to pay the price, commitments to clean coal can be made over any period of time.

The only real barriers to large coal companies investing in PCC are market (and technical) uncertainty, as no doubt is often expressed to coal companies by utilities. For the time being, utilities in many areas can burn coal in noncompliance.

A final matter concerning large companies, those which can afford to invest in PCC, needs to be noted. It is a matter to which we return later in this section; that is, that large coal companies do not and probably will not invest in PCC for principally individual small volume coal consumers. To do so would prove impractical from both the coal company's (financial) point of view and from the consumer's (economic) vantage.

Small Coal Companies. Currently, about 15 percent of the nation's coal is produced in about 80 percent of the nation's mines. Generally, coal produced at these mines (about 4,000 of them) is sold without any preparation. It is shipped at single-car rates, which means it costs \$2 to \$3 more a ton to ship this coal than it does to ship coal produced in the same area from large mines. Coal produced at large mines, if it is going to large volume markets, is shipped at unit-train rates.

In order for firms to take advantage of unit-train rates, several conditions must be met. The most important of these are high volume movement between a single source and single market and a means by which to load unit-trains quickly and efficiently. A coal transloader is necessary to perform this task. A transloader may involve about a \$7 million to \$12 million dollar capital investment, with about a \$1 million annual operating expense. Small coal producers are not in a position to afford such investments. Their production is too low to make it economically attractive.

Existing preparation plants are very often located adjacent to transloading facilities. Of course this means an additional capital expenditure, and again, small producers are not in a position to make such investments.

Given this environment, it should be noted that a significant fraction of cleanable reserves may now be controlled by small producers, especially those in central Appalachia. How might these resources be tapped?

One possibility is for small producers to have their coal cleaned at the PCC plants of large firms. One such arrangement has been working for ten years

in Appalachia, Virginia. Here a coarse preparation/transloading operation is set up to serve two utilities in North Carolina. General Coal Company (Westmoreland) financed and operates the facility. The facility is built at the site of a Westmoreland mine which accounts for 1.6 million tons (40 percent) of the facility's 4 million ton yearly throughput. Another 35 percent comes from smaller Westmoreland mines, some of which are operated by independent contractors, located within 25 miles of the facility. Fully 25 percent of the coal comes from the mines of small independent coal producers in the area.

Without access to this facility it is doubtful that the production from the small independent mines would have a market. In the future, if PCC plants are to be built principally for sulfur removal purposes (naturally ash removal cannot be ignored since boiler designs are very sensitive to the ash content of intended coals), relationships such as this may flourish. However, the coals which would be washed at such facilities must have similar heat, ash, and sulfur contents to make the arrangement work. Further, and very importantly, the small independent producers must feel they would be getting a square deal by participating in such an arrangement. As matters now stand, because in many cases such producers have no market without coal prep--as well as transloaders and unit-train rates--there is nothing to keep large coal companies from extracting a rather high price for the service they may provide the small producer. Presumably antitrust provisions might provide a measure of economic protection in this regard; still, the perceptions small producers may develop for such arrangements may lead them to seek alternatives.

One alternative is for small producers to form cooperatives for the purpose of financing capital investments such as a PCC plant. Co-ops have been successfully organized and operated in several fields of commerce, most notably in agriculture.

Cooperative relationships permit small firms to pool their resources in an equitable manner and to take advantage of certain tax provisions and financing mechanisms. For a variety of reasons, however, co-ops take painstaking effort to establish and even greater effort to maintain.

The basic problems with co-op formation and maintenance have to do with reliability, trust, and the need to place the interests of the collective ahead of the interests of the individual members in the event that these interests diverge. Small coal producers have a reputation, deserved or not,

for being independent-minded--some call it unreliable. Such producers may be very uncomfortable with such things as production quotas. Yet co-ops are established such that if one member fails to make a fair contribution, all other members will suffer.

Another barrier to the successful formation of coal co-ops involves the fact that purchasers of coal may not believe these relationships will last. If so, they may not wish to commit themselves to long-term contracts for co-op coal. The purpose of co-op formation with respect to PCC facilities is of course to get in a position to land a long-term contract. Without such a contract, large new capital investments--e.g., in PCC, transloader or railroad rolling stock--would certainly seem imprudent and would very likely not be feasible.

There are other possible means by which the cleanable reserves of small coal companies could be brought into the marketplace. One is through the business consolidation of small firms. With the impact of surface mine reclamation and mine health and safety legislation having a strong effect on the prospects for small firms in particular, there is reason to believe consolidations will take place, if bankruptcies do not occur first.

The final possibility we consider is that joint ventures might be formed between small coal companies and coal consumers. This possibility is discussed under the heading of institutional barriers faced by industrial firms.

Electric Utilities. Ultimately, the question of what the appropriate sulfur removal strategy might be focuses on what is emitted from a given stack. Accordingly, utilities and other coal-burning firms are ultimately responsible for seeing that emissions are at acceptable levels. The operations of coal producers will not be shut down; the operations of utilities could be. Hence, if physical coal cleaning investment will help prevent plant closures and if utilities would like to have such investment made for them, large coal companies--with appropriate financial protections--will invest.

Before the utility gives its approval for a PCC investment, it must be reasonably certain of several things. These include:

- Whether the PCC investment appears to make economic sense
- Whether PCC should be combined with other compliance strategies, e.g., FGD retrofit (and/or) blending

- Whether it is better to clean the coal at the mine, at the plant, or both
- Whether the PCC plant ought to be designed to accommodate the needs of existing boilers alone or whether some flexibility for multistream operations should be incorporated in the PCC plant design
- Whether a PCC investment ought to be evaluated on its ability to serve existing boilers or on some other basis
- Whether existing boilers will need modification to accept coals that have, for example, been deep cleaned
- Whether it would be cheaper or better, i.e., more reliable, to enter into a long-term contract for cleaned coal, to engage in a joint venture with a coal company, or to move toward a captive mine/plant situation
- Whether a public utility commission (PUC) would approve fuel passthrough clause treatment of PCC if a coal company were to invest
- Whether a PUC would approve PCC for whole or partial rate base inclusion if the utility were to invest
- Whether a PCC investment could be made most advantageously by an unregulated subsidiary, perhaps in a joint venture.

Uncertainties as to future SO₂ limitations and the relative economics of different control options and their combinations are the key factors inhibiting PCC investment. The following paragraphs describe some of the concerns which electric utilities would have in contemplating and perhaps attempting to establish the institutional arrangements necessary to make the PCC investment.

The first consideration is whether to locate the PCC plant at the mine, at the generating plant, or at both places. Naturally mine-mouth generation eliminates the need for this consideration. Where source and use of coal are physically separated, it can be argued that a coarse clean at the mine and a deep clean at the power plant has definite advantages.

One advantage is that it would not make obsolete existing prep plants operated by coal companies at their mines. Further, it would mean transport cost savings could be realized, whereas this would not be the case if all cleaning were done at the power plant. If all cleaning, including a deep

clean, were done at the mine, there would be a question as to the net effect on transport costs, since a deep clean produces a very fine-sized coal, one that requires well-maintained hoppers. For example, it could require bottom-dump cars that shut very tightly. Finely crushed coals may also require covering to be transported, both for environmental and economic reasons.

Another possible advantage to this type of arrangement is that total refuse disposal costs might be reduced if some disposal were done at either end. While it may appear odd to suggest having two prep plants and therefore two disposal sites, there could well be circumstances under which this would be the preferred arrangement. One potential situation where the idea may be especially attractive is in the event of having at least one generating unit, which has a scrubber, that is close to the prep plant. This scrubber will require a waste disposal site in any event. This site may be used for both FGD and PCC wastes.

Other advantages to having the deeper clean at the power plant may include being able to blend prior to beneficiation and being able to use the waste heat from the power plant to remove moisture. None of these advantages may prove compelling in a given situation, particularly when substantially more capital and operating costs would be involved in providing two facilities. Nevertheless, because institutional, contractual, and financial problems may be avoided in continuing to have coal companies do a light prep at the mine and making the investment in heavy prep at the power plant, this option should be evaluated on a case-by-case basis.

A second and related consideration is whether a utility might invest in PCC to serve more than one plant in the present or in the future. If, for example, a PCC application were intended solely for an existing inner-city power plant, one that had only seven or eight years of useful life remaining, the utility might understandably opt to have the PCC plant, waste disposal sites, etc. located away from the power plant. However, if the application were intended, let us say, for one or perhaps two existing units with decades remaining in their useful lives and could be used for future units at the same site, the decision on location and ultimately on the economics of the entire PCC proposition could be quite different.

In considering these options, a utility is very likely to keep in mind the possible views of PUCs to the various institutional, economic, and financial arrangements the utility may propose. PUCs, like utilities, are

under constant and conflicting pressures to ensure that electricity will be supplied on a reliable basis at lowest reasonable cost. Maintaining an acceptable balance between concern for reliability and concern for least cost can prove very difficult. This is especially so because electricity and cost determination must be made on a prospective basis, requiring use of forecasting techniques.

More stringent environmental regulations tend to have adverse effects on both anticipated reliability and anticipated costs. In this regard, control options for SO₂ emissions from existing and new coal-fired plants simply add another set of factors for PUCs to take into account.

One of the ways utilities have been responding to concerns for both reliability of coal and electricity supply and of cost is relying more heavily on long-term contracts. At the same time, growing numbers of utilities are entering the coal mining business to produce for their own needs (and sometimes for the needs of other utilities).

In 1976, captive coal represented about 11 percent of all coal delivered to electric utilities. By 1985, this figure is expected to rise to about 19 percent. Utilities now control about 10 percent of recoverable coal reserves in the U.S. Two-thirds of these reserves are in the western states.

Utilities that are getting into the coal business are generally large--Texas Utilities, TVA, AEP, Pennsylvania P&L, and Duke Power being notable. However, smaller utilities are considering cooperative ventures to produce for their member needs. The Western Coal Association is the first example of a co-op being formed (by ten utilities) both for fuel procurement (contracts negotiated with independent producers) and production purposes.

The significance of these developments for PCC is that utilities could be in a position to invest in their own cleaning facilities at the mine--be it mine-mouth generation or not. Moreover, with the apparent willingness of at least some PUCs to permit such vertical integration, utilities may gain valuable bargaining strength in negotiating with independent coal companies for coal, including cleaned coal.

However, it should be noted that not all PUCs view the benefits (quantifiable and nonquantifiable) of vertical integration as greater in all cases than the costs. That does not mean such PUCs would necessarily disapprove of vertical integration; instead, it might mean they would make the possible financial advantages to the utility in the arrangement less apparent.

The three advantages identified thus far to utilities in captive operations are:

- Greater reliability of supply
- Potential for lower costs for fuel
- Leverage in negotiating contracts with independent coal companies.

Other possible advantages include:

- In the case of unregulated subsidiaries, the potential for greater return on equity than may be likely on regulated aspects of the business
- Tax advantages.

The first of these other advantages will not always be realized. There are business risks to consider, though presumably with an assured market this risk is reduced. PUCs may see this risk reduced to the extent that it does not "allow" a captive supplier to earn a greater return than is allowed its parent. (In fact, however, a PUC cannot really control the return on equity; this is determined in the business and financial marketplace.) The PUC's choice of transfer-prices between supplier and purchaser can prove a disincentive to vertical integration and, hence, an institutional barrier to PCC investment.

On the other hand, mining investment (and, under certain circumstances, prep plant investment--a matter discussed in the next section under the heading of economic barriers) makes available several types of tax shelters for income earned by parent companies. For example, the costs of exploration and development of a mine can be deducted in the year in which expenses were incurred, even if the mine had no income in that year. Also, both lease and outright purchase acquisition of coal reserves offer tax benefits. In the former case, advanced royalty payments (paid by the lessee, the utility), which will later be recouped in production royalties, can be deducted from the utility's gross income in the year in which these payments were made. In the latter case, a depletion allowance is made available to a utility--one half of net income--as lessor to an operating subsidiary. Alternatively, instead of taking a depletion allowance on royalty payments, a utility can treat royalty payments as capital gains, and thus subject to a lower tax rate.

There are definite disadvantages to utilities moving into captive operations. Probably the most significant of these is that utility management

has not had a great deal of experience in dealing with mining companies and miners. Electric utilities are capital, not labor, intensive. A different set of skills may be required for captive operations. Further, management resources might be better applied at the very complex generation, transmission, and distribution end, rather than spread across another area.

The issue of management skills is important, too, when considering PCC operations. Because coal companies have traditionally managed the efforts of preparation engineers, they have an advantage in considering a PCC investment for sulfur removal purposes. Power engineers definitely speak a different language than do preparation and mining engineers.

In sum, there are advantages and disadvantages in the utility move to captive coal and the possibility of coal washing for purposes of sulfur removal. PUCs will weigh the relevant factors, as will utilities. It cannot be said now for certain that PUCs will prove an institutional barrier to PCC investment. If PCC in captive operations could be demonstrated as the clear-cut, least-cost way to go in order to produce environmentally acceptable coal, presumably PUCs would approve the plan.

Industrial Coal Consumers. At present, by and large, industry's problems are with coal, not coal cleaning. Most of industry has not used coal for a long time. Managers have been spending the last two decades learning about oil and gas contracts. Many have only heard stories and seen pictures of cities like Pittsburgh when coal was the predominant fuel. Many now express resolve not to burn coal no matter how attractive the coal option may appear due to investment tax credits, conversion tax credits, oil and gas taxes, incremental pricing for new gas, inverted electricity rates, and so on.

This is the general sentiment in the industrial sector. However, there is reason to believe that many firms are now at least considering coal. Among those which are likely to be thinking about coal, and therefore about ways in which to burn it in an environmentally/economically acceptable manner, are:

- Firms that are now or could be located near coal deposits
- Firms that would have relatively high-volume needs for coal
- Firms that have space available for coal storage, rail facilities, and PCC waste disposal.

- Firms that have boilers which now burn oil or gas, but which were originally designed to burn coal
- Firms that have experienced major gas curtailments
- Firms that need a fuel for process uses because electricity will not do the job
- Firms (really, managers) who view dim prospects for coal gasification and natural gas deregulation
- Firms (managers) who might be persuaded by conversion incentives and/or oil and gas taxes to switch to coal
- Firms (managers) who believe the competitive firms will be no better off by doing something other than going with coal
- Firms (managers) who believe that a consortium of industrial firms could be established and maintained to procure and clean coal, if necessary, on a large-volume basis
- Firms (managers) who believe joint ventures could be established between coal customers and coal producers, either individually or in a consortium
- Firms (managers) who may see a possibility of participating with a utility in a multistream coal cleaning operation.

As the list indicates, the majority of concerns that current or would-be coal consumers have are more legislative, technical, economic, and financial than they are institutional. In fact, only the last three concerns have to do with specific institutional-type barriers. Nevertheless, it will prove useful to review briefly the noninstitutional type concerns in this section, because such a review will offer a better perspective of institutional problems.

Industry purchased about 60 million tons of coal in 1976. The great majority of industrial purchases were under 100,000 tons that year. This coal moves almost exclusively at single-car rates. Hence, coal transportation cost for industry are relatively high. Accordingly, industrial coal consumers will locate as closely as possible to sources of supply. Only unit-train rates would permit them to consider moving farther away.

One of the largest problems involved in expanded near-term use of coal by industry is that the technical feasibility of converting units designed for oil and gas is by no means well understood. Hence, many consider the

prospects for converted units as limited to those which were originally designed for coal firing.

Another problem involves space--space to store coal, space to run in rails, space to put refuse from either PCC plants or FGD systems. In many cases industrial firms had planned to build new boilers near existing boilers. Use of coal makes such siting impossible in many cases. Even where space is not of critical concern, an existing plant site might well be made obsolete, if coal were intended to be used, by SIP's or the economics of future offset policies.

Many firms surveyed in the course of this study wished that legislators and regulators would better appreciate that industry in general is not in the same monopolistic, large-volume coal use, relatively good bargaining position that characterizes the electric utility industry. Some looked forward to the prospect of burning coal, especially to the prospect of burning it without having to install scrubbers, if institutional arrangements could be worked out.

The principal purposes of new institutional arrangement would be to:

- Strengthen bargaining positions for the negotiation of coal prices
- Reduce transportation costs
- Facilitate the financing of transloaders, unit-train rolling stock, and PCC plants where such plants are proven effective in helping firms meet forthcoming industrial boiler New Source Performance Standards.

One new institutional arrangement being considered involves the formation of a consortium of firms, the functions of which would roughly parallel those of the utility co-op Western Coal Association. That is, the consortium would negotiate contracts with independent coal producers; it would acquire leases; and, it would develop mines, as needed. In this section, we have discussed cooperative arrangements between small coal producers, electric utilities, and now industrial coal consumers. Of the three types of arrangements, probably the greatest difficulties in formation and maintenance of the associations would be experienced by small coal companies; probably the least by utilities; and industrial associations of this type would probably be somewhere in the middle.

The major reason why industrial consortia would appear more fragile than similar arrangements between utilities is that industries as a

whole experience a considerably higher degree of business risk. This fact is manifest to some extent in contractual arrangements. Because they are afforded the luxury of monopoly status, utilities can plan decades ahead and desire to have long-term supply contracts. Industry contracts, relative to utilities', are decidedly short term (again, see Appendix C for a greater discussion of contractual arrangements).

Because industry must remain flexible, its planning horizon cannot go out very far unless it is willing to accept the possibility of a change in the nature of its business for periods of time or to accept a higher degree of business risk. For example, if one member of an industrial consortium is unable to consume its share of coal in a given year, it must expect to have to market it elsewhere, perhaps at a loss.

If firms were committed to one another in a consortium, there would appear to be no reason why long-term arrangements could not be maintained. Consortium-type arrangements, with emphasis on the long-term aspect, would appear necessary for firms to contemplate financing mine development, trans-loaders, and PCC plants. Without reasonable assurance that commitments would be honored, that losses would be absorbed, and that firms would not go bankrupt, consortia would not be formed.

Also noteworthy as a possibility for a new institutional arrangement is joint ventures between industrial forms and coal companies. The prospects for such arrangements may not be good unless, on the one hand, industrial firms form associations and, on the other, large coal companies or coal company cooperatives are involved. There is great risk involved in situations where one party to the venture is much larger than the other (the larger party assumes the risk). It is difficult to see what advantage an industrial consumer would have in engaging in a joint venture with a small coal producer.

The final set of problems to be considered here, relating to the institutional arrangements which might be sought by industrial consumers to enable them to use coal in an environmentally acceptable manner, involves the possibility of using the facilities of electric utilities. Specifically, industrial firms may wish to contract with or enter into joint ventures with utilities to use blending or PCC facilities located at power plants. An arrangement such as this has several advantages for both parties. For utilities, the benefits may include:

- Assistance in the financing of blending and/or PCC facilities, as well as disposal facilities
- Assistance in defraying the cost of facilities
- Possible economies of scale in scaled-up facilities
- Possible greater savings in transportation costs
- Possible sale of waste heat to industrial firms
- Possible attraction of a "captive" market for electricity sales.

For industrial firms, the benefits may include:

- Transportation cost savings
- Assistance in the financing of the facilities
- Access to middlings which would otherwise have to be disposed of as refuse
- Reduced refuse disposal costs
- Elimination of the necessity for FGD
- Assurance that prices charged for blending and cleaning are reasonable, since there would probably be access to utility accounting records.

Many potential problems are involved in setting up and maintaining such an arrangement. The most basic of problems have to do with the different standards to which utility and industrial boilers may be subject and with what may be the least-cost or most risk-averse solution to each party. Depending on the boiler or boilers it has at the site and depending on the coals it wishes to use, the utility may have a quite different blending and/or coal cleaning configuration in mind than what would be optimal from the industrial user's point of view. Something so basic as the question of whether to design for least-cost compliance or adopt a most risk-averse posture would be at issue (e.g., risk-aversion may imply use of scrubbers in fear that SIP's might be tightened eventually to levels which use of no other technology could satisfy).

There are also rather basic problems as regards utility regulation. Industry may fear that if it invests in the facilities, regulatory authorities may have the right to scrutinize its accounts and ultimately regulate its returns on investment as well. PUC's may also take interest in the contractual arrangements entered by utilities and industrial firms, and could require as protection of the investment that these contracts be of a long-term variety.

Adequacy of Commercial PCC Demonstration

It is not surprising to find that a significant factor in the lack of widespread enthusiasm for PCC as a sulfur removal strategy lies in the fact that it has not been proven a practical or effective control strategy. Theoretical and tenuous engineering cost data, largely deduced from information on ash removal, provide a wholly inadequate basis for investment decisions. Given the nature of these data and the genuine desire of potential investors in PCC to be provided with information on this control strategy, it would appear desirable to devise commercial demonstrations and collect relevant "investment decision-grade" data at the earliest time practicable.

As for the type of demonstration which may be most useful, it would appear that an arrangement which yields hard data for a variety of potential investors would be most cost-effective. In this regard, there are five potential markets for which PCC may be a suitable control strategy. These markets are:

- Electric utility boilers subject to SIP's
- Electric utility boilers subject to NSPS
- Electric utility boilers subject to forthcoming NSPS revisions
- Industrial boilers subject to SIP's
- Industrial boilers subject to forthcoming NSPS.

If a demonstration could be devised such that at least the NSPS (utility and industry) and revised NSPS applications could be explored, this would contribute a great deal to the understanding of PCC as a control strategy. If such a demonstration could include experiments of PCC in combination with FGD, blending, and a variety of types of coals, data for a broad cross-section of possible PCC applications would become available.

In terms of a specific type of situation in which to test the commercial prospects for PCC--for a variety of applications, in a variety of combinations--a situation such as that described earlier in this section, one involving the joint participation of an electric utility and at least one nonutility industrial firm, may be an especially rich situation. As an important adjunct to designing a demonstration such as this, a great deal of insight could be gained in understanding institutional barriers which inhibit PCC investment.

Characteristics of Coal Market

As part of this review of institutional barriers which may inhibit adoption of PCC as a sulfur removal strategy, an effort was made to determine whether the current market is now or is tending to become characterized as a "seller's market" in which utilities are forced to "take what they can get". We found no evidence to support this broad characterization. We did find evidence that some utilities are not entirely pleased with the coal they are receiving and evidence that others are having difficulties lining up suppliers. On the other hand, we found suppliers who were not pleased with the long-term contracts they now have with utilities and others who were having difficulty identifying markets. Noteworthy in this regard are western coal producers who, with the effects of NSPS revisions on the likely least-cost coal development patterns beginning to be appreciated, are concerned.

Control of Cleanable Reserves

To our knowledge, truly reliable data on the cleanability of U.S. coal reserves do not exist. To our knowledge, the same holds true for the reliability of data on the holding of specific reserves in the U.S. by specific firms. Hence, we cannot estimate whether or to what extent such reserves are being kept or may be kept from the marketplace.

PCC Is Not Considered a Pollution Control Investment

Traditionally, physical coal cleaning has been performed for purposes of ash removal. Of late, the focus has widened to recognize the ability of PCC processes to remove sulfur as well. Because emissions standards are being made more stringent in many cases and because the stringency of these standards is forcing utilities and some other coal-burning firms to incur the high cost of either contracting for low-sulfur western coal or installing scrubbers, efforts are being focused on PCC, which may be a lower cost compliance option.

One factor which may inhibit the adoption of PCC as a sulfur emissions control strategy is that, unlike FGD systems, coal cleaning does not qualify

for tax purposes as a pollution control investment. This determination is made by the Internal Revenue Service, and the effect of this ruling on the part of the IRS is to put PCC on an unequal (that is, more expensive) footing vis-à-vis scrubbers. The IRS ruling is based on the agency's belief that PCC investments are made principally for purposes of gaining a commercial advantage over firms that do not clean the coal they sell. The fact that substances which might pollute are removed in the cleaning process would be seen as incidental to the essential purpose of the investment--to repeat, to gain commercial advantage.

A section in the 1977 amendments to the Clean Air Act may suggest that the IRS could be urged to reconsider this ruling. Section 111 (a) (1) gives the EPA administrator authority to permit "credit" toward the percentage removal requirement in NSPS revisions for precombustion cleaning of coal.

There are many precombustion coal cleaning processes, and perhaps at some time one of these, or a combination of them, may clean the coal to the extent required under NSPS revisions, at a calculable cost. For the time being, however, it appears that precombustion cleaning must be combined with FGD to achieve, say, an 80 or 90 percent sulfur removal. Since "credit" may be given for both types of sulfur removal, this would appear to offer prima facie evidence that precombustion cleaning, e.g., PCC, is placed on an equal footing with postcombustion cleaning as a pollution control strategy.

If PCC were granted status as a pollution control investment, three financial/economic benefits would be made available for such investment:

- Accelerated depreciation, that is, over five years, could be taken for tax purposes (presently, a PCC plant can be depreciated only over its anticipated useful life).
- A 5 percent investment tax credit could be taken (prior to 1977, pollution control investments qualified for either accelerated depreciation or a 10 percent tax credit, not both).
- Tax-exempt pollution control revenue bonds (PCRBs) may be used to finance the investment. (Because tax-exempts now flood the narrow tax-exempt market and because PCRBs are unsecured debt, use of PCRBs by firms whose financial positions are not robust may be of marginal benefit.)

Expanded Use of Indigenous Coals

Because the 1977 amendments to the Clean Air Act provide governors of states with the authority to rule in favor of the use of indigenous coals, it is feared that such a ruling may cause imported low-sulfur coals to be replaced with high-sulfur local coals. But to make it possible to expand the use of these high-sulfur coals, SIP's may have to be greatly relaxed.

The alternatives are to relax the SIP standards a little, leave the SIP's unchanged, or even tighten them. These alternative courses of action may suggest applications for PCC or FGD.

The barrier to PCC in this instance would appear to be socioeconomic in nature. If governors opt to promote use of indigenous coals high in sulfur content, and if SIP standards are not greatly relaxed, electricity prices may be adversely affected. Also, some argue that economic growth would be stymied and employment opportunities would be generated at a reduced rate.

It can also be argued that, no matter how stringent or how little relaxed the SIP standards, there would be no net effect on electricity prices if the presumed lower cost of indigenous coals exactly offset the cost of increased pollution control expenditures. As for economic growth and employment opportunities, the intended purpose of the indigenous coals options is to promote local growth and employment. Moreover, all expenditures--be they for power production or pollution control--would add to gross state product.

Utilities May Be Unable to Raise Capital for PCC

Concern has been expressed about the ability of electric utilities to raise capital for investment in PCC facilities. The concern is based on the belief that neither utilities, nor those who lend to them, nor the public utility commissions which regulate them would wish to invest in a technology, such as PCC, which is unproven from an economic point of view.

This is, in a very real sense, a legitimate concern. No utility--or for that matter, coal company, nonutility industrial firm, or independent investor--can be assumed as likely to invest in a technology the technical/economic characteristics of which are largely unknown.

Demonstration projects may be necessary to prove the value of physical coal cleaning as a sulfur removal strategy. Partial investment by utilities and/or other types of firms may be sought by the EPA. Such investment may be made by a utility if it feels that the PCC facility will help it solve a specific problem--either in the short-term, e.g., a problem with SIP compliance, or the long-term, e.g., it is curious as to whether there are whole or partial alternatives to scrubbers.

Another important factor to a utility in deciding whether to participate in a demonstration is whether or not its PUC will approve the expenditures as an investment or cost which may be recovered in consumers' rates. If a PUC were inclined to have a utility's investors bear the cost rather than its consumers, there would be a definite disincentive to make such investment.

A final point needs mentioning. Although the cost-effectiveness and other aspects of a proposed utility investment sharing in a PCC demonstration will be given much project-specific scrutiny, it should be noted that utilities are not necessarily prevented from making an investment simply because a technology is unproven. Their overall financial position in general permits them to make fairly sizeable investments in projects the risks of which are considered substantial.

Coal Companies May Prefer New Mine Investment

Another possible barrier to investment in PCC could involve the view of coal companies with respect to alternative investment opportunities. In particular, it is thought that coal companies would prefer investing in new mine capacity to investing in PCC plants. It is difficult to generalize on this matter. Although it is certainly true that, as matters now stand, PCC is a risky proposition; so too are lease acquisition and mine development. Risky propositions must as a general rule have appropriate anticipated payoffs--either in higher returns or in improvement or maintenance of market position. All of such assessments are based on probabilities, are prospective, and are, therefore, subjective.

Coal Companies May Be Unwilling to Offer Long-Term Contracts for Cleaned Coal

An issue which is certainly related to the previous one, concerning preferences of a coal company for certain types of investments, is whether coal companies are now or would be unwilling to offer cleaned coal on a long-term basis.

Presumably one concern is that coal companies may see no future in coal cleaning as a sulfur removal strategy and would not offer a service they did not believe in. In fact, the majority of coals now going to utilities under long-term contracts are cleaned coals. Furthermore, a long-term contract is very likely to be a practical necessity for investment in PCC to occur.

Finally, there is absolutely no reason to believe that coal companies would withhold a service--such as a PCC process which maximizes or optimizes sulfur removal--simply because they do not believe in it. If there were a guaranteed or reasonably certain market for such a service, if a reasonable return on investment could be anticipated, and if some financial protection were afforded such investment, e.g., through a long-term contract, coal companies could be expected to invest.

Regulatory and Legislative Barriers

Some of the major barriers to PCC investment lie in the legislative and EPA regulatory areas. In this section, we identify the major factors in these areas which now concern potential investors in PCC. Further, we assess the relative effect that continued uncertainty in certain areas is likely to have on the prospects for near-term adoption of PCC as an SO₂ emission control strategy. The regulatory and legislative factors we assess include:

- Enforcement of SIP standards, averaging periods, and variances
- Uncertainty surrounding the permanence of any SO₂ emissions standards
- Air and water pollution standards for prep plants
- Legislative incentives for industrial use of coal.

Enforcement of SIP Standards

The major factor inhibiting efforts to do anything about evaluating SO₂ control strategies is the lack of enforcement of SIP standards. While many firms' plants are on compliance schedules, many are not. As a result, noncompliance has become for many firms the most reasonable, that is, least-cost solution to problems with SO₂ emissions.

That is not to suggest that firms will necessarily go out of their way to avoid investment in coals or processes which might enable boiler operations to be in compliance with standards. To seek consciously and purposefully to avoid compliance--without, for example, bothering to plead for variances--could lead to legal action.

Uncertainty Surrounding the Permanence of Any Standard

In the course of our survey of would-be investors in PCC as an SO₂ emissions control strategy, one crucial barrier was mentioned by virtually all with whom we spoke; that is, that planning to invest in control strategies is greatly complicated by the fact that the targets keep changing. Further, few venture to make estimates of where the standards are going, how fast they are likely to move, and where they are likely to end up. (Some suggested facetiously that they would end up at zero emissions.)

The obvious problem this suggests is that an investment in PCC, for instance, could become obsolete overnight with either a more stringent standard or a redefinition of BACT and/or a redefinition of where the old or new BACT should be applied.

EPA would not wish to inhibit the development and introduction of new pollution control technologies, the prospects for which may be bright over the medium-to-long term. Yet, on the other hand, the agency would not wish to inhibit the adoption of existing technologies or ones, like PCC, that show great promise for near-term application.

This clearly presents a dilemma for the EPA. Should it grandfather in investments such as PCC? If so, for how long? If the plant were built near the boiler, for the life of the boiler? What if other boilers were built at the same site; could the PCC plant be used? If the PCC plant were located

at a mine, would it be grandfathered for the life of the supply contract over which its cost is expected to be recovered? What if the contract were abrogated or renegotiated? These and many other questions may need to be answered--on a firm-specific, boiler-specific, contract-specific, site-specific basis--before PCC investments can be made.

Pollution Standards for PCC Plants

If current problems with air and water quality standards for prep plants are any indication, there may be serious regulatory and ultimately economic constraints on their siting and, hence, on the desirability of adopting PCC as a control strategy.

Potential investors point in particular to the effluent requirements applying to new prep plants as evidence that these plants may cost a great deal more than now anticipated to site and operate. Solid waste is also a problem, as are air emissions.

There are indications that some new prep plants have been sitting idle for more than a year, in large part due to the economic and technical feasibility of making them environmentally suitable for operation.

There is a feeling among potential investors that environmental standards for PCC plants may become more stringent--another moving target. Investors are uncomfortable with situations in which they do not have a reasonable certainty of what it will cost to build (and perhaps rebuild) and operate a plant over its useful life.

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